

Date Mailed January 15, 1999

BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation For Approval 6690-UR-111
to Increase Electric and Natural Gas Rates

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

On April 1, 1998, Wisconsin Public Service Corporation (“WPS” or “Applicant” or “the company”) filed an application with the Public Service Commission of Wisconsin (Commission) for authority to increase its rates for electric and natural gas service. At the same time, WPS prefiled 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 15, 1998. The Applicant requested an increase in electric rates of \$36.2 million, or 8.6 percent, and an increase in natural gas rates of \$11.2 million, or 5.7 percent, in 1999. For 2000, WPS requested an additional increase in electric rates of \$24.3 million, or 5.4 percent, and an additional increase in natural gas rates of \$1.5 million, or 0.8 percent.

A prehearing conference was held on July 13, 1998, to define the issues and establish a hearing schedule. Pursuant to due notice, public hearings were held in Green Bay on September 14, 1998, and in Wausau on September 15, 1998. Technical hearings were held in Madison on September 30 through October 2, 1998, and on October 6, 1998.

The parties for purposes of review under Wis. Stat. §§ 227.47 and 227.53, are listed in Appendix A. Other persons who appeared are listed in the Commission’s files.

A rate increase in the amount of \$26,942,000 annually from present rates is authorized for Wisconsin retail electric utility operations, a 6.3 percent increase, and a rate increase of \$10,280,000 annually above present rates is authorized for Wisconsin natural gas operations, a 5.1 percent increase. Rates are based on a 12.10 percent return on common equity.

FINDINGS OF FACT

THE COMMISSION FINDS:

Applicant and Its Business

WPS is a public utility, as defined in Wis. Stat. § 196.01(5), engaged in the production, transmission, distribution, and sale of electricity to approximately 375,000 customers, and in the purchase, distribution, and sale of natural gas to approximately 218,000 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 plant at Sheboygan, which it owns jointly with Alliant-Wisconsin Power and Light (Alliant); and Columbia Nos. 1 and 2 plants near Portage, which it owns jointly with Alliant and Madison Gas and Electric Company (MGE). 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 transmission connections for purchasing electricity from other utilities and, together with Alliant and MGE, jointly owns the Kewaunee Nuclear Power Plant (Kewaunee). In addition, WPS signed a long-term contract with De Pere Energy LLC, a wholly-owned subsidiary of Polsky Energy Corporation, to purchase virtually all of the capacity of the De Pere Energy Center, a 180-MW simple-cycle natural gas-fired combustion turbine, beginning in mid-1999.

WPS obtains 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 1999 Wisconsin retail electric and gas operations, as well as known and significant events expected to occur in 2000. Significant issues pertaining to the income statements are treated separately below.

Kewaunee Mid-cycle Shutdown Refund Amount

In the company's last rate proceeding, the Commission authorized WPS to recover costs related to a 1998 refueling outage at Kewaunee as well as costs associated with a mid-cycle shutdown at that plant. Because of the uncertainty about whether the mid-cycle shutdown would be necessary, the Commission ordered both the fuel and non-fuel costs associated with this shutdown to be made subject to refund in the event that one or both of these outages did not occur. Different mechanisms were established for determining any refunds necessary for the fuel and non-fuel portions of these costs. For the non-fuel portion, the Commission ordered one-half of the total amount included in rates be refunded in the event that only one outage occurred.

Because the mid-cycle shutdown did not occur, WPS included a forecasted refund in its filing in this proceeding. Since the order in the last rate proceeding was issued 51 days after the start of the test year, WPS reduced the amount of the refund included in its test year forecast in this proceeding, on a prorated basis, to reflect the fact that it did not recover all of the costs that were set subject to refund. The Commission finds it reasonable for the amount of the refund to be reduced in this manner and that the revenue requirement should reflect a refund of \$2,558,950 to Wisconsin retail ratepayers over the biennial period.

Services Provided to UPPCO

In the company's last rate order, the Commission determined that the services provided to Upper Peninsula Power Company (UPPCO) are a "utility function whose revenues and fully-allocated costs shall be assigned to the wholesale jurisdiction." In this proceeding, WPS requested the Commission to reconsider its determination in the company's last rate proceeding and to allow the utility to treat this activity as a revenue credit (or as a retail activity) for ratemaking purposes until a decision can be made regarding the accounting for this activity in docket 05-BU-101. The Commission reaffirmed its previous decision regarding this matter and ordered WPS to assign revenues and fully-allocated costs associated with this activity to the wholesale jurisdiction. Since no information was included in the record in this proceeding regarding fully-allocated costs associated with provision of these services, the Commission determined it is reasonable to use the relationship of fully-allocated costs to revenues associated with gas servicing as a guide for estimating the fully-allocated costs associated with the services provided to UPPCO. In the utility's last rate proceeding, the Commission ordered WPS to begin accounting for gas servicing as a nonutility activity, on a fully-allocated basis. In this rate proceeding, WPS forecasted its fully-allocated costs associated with gas servicing in the test year to exceed revenues by 30 percent. In the absence of better information, it is reasonable to estimate the fully-allocated costs associated with services provided to UPPCO to exceed revenues by 30 percent. In this proceeding, the Commission determined that revenues of \$283,000 and fully-allocated costs of \$368,000 associated with services provided to UPPCO shall be assigned to the wholesale jurisdiction.

Open Access Transmission Tariff

In 1996 the FERC issued Order 888 on open transmission access, requiring WPS to file an open access transmission tariff (OATT). WPS chose to enter into a settlement agreement with its wholesale customers to establish the transmission rate, which was approved on May 27, 1998,

to avoid the considerable cost of litigating the case and to avoid the potential result of receiving lower rates in that process than the settlement rates to which the company agreed. The rates WPS agreed to under the settlement are less than the fully-allocated cost of transmission in this proceeding.

The Commission determined that, because wholesale customers who take service under the OATT receive the same level of transmission service as firm retail customers, the costs associated with serving these wholesale customers should be treated the same as for firm retail customers. The Commission finds it reasonable that the revenues and fully-allocated costs associated with this activity be assigned to the wholesale jurisdiction. It is also reasonable that the fully-allocated transmission rate be used to determine the reduction in the revenue credit to firm customers from the electric interruptible demand charge.

Executive Short-term Variable Pay Plan (STVPP)

WPS requested additional rate recovery of \$305,000 to provide incentive pay for its ten key executive employees. WPS provided testimony that it approved the creation of the STVPP in February 1998 as a way to provide key employees the opportunity to earn additional variable pay based on exceptional performance.

Commission staff testified that the criteria for payouts and how the criteria would be objectively measured had not been adequately developed, that WPS had not adequately demonstrated its executives are compensated below market, and that there is not an executive turnover problem.

The Commission finds WPS has not presented sufficient support in this proceeding to show that ratepayer benefits of the incentive plan outweigh the cost of the plan. Ratepayer benefits related to qualitative measures, including customer service as well as payout triggers, need to be well defined before rate recovery for an incentive plan is considered. The Commission finds it is not reasonable to include estimated STVPP payments in the 1999 test year revenue requirement.

Non-union Pay Increases

WPS requested additional rate recovery to provide for three modifications to its non-union compensation structure. Its request included \$750,000 in the test year budget over and above inflation to match market rates, \$192,000 to shorten the length of pay progression for some non-union positions, and \$973,000 to move the May and July 1999 annual pay structure increases forward to January 1999 for non-union employees without adjusting for the annual wage increases that already occurred in May 1998 and July 1998.

The Commission finds there was not an adequate record to support rate recovery for increased non-union compensation rates and shortening of the non-union pay progressions. However, the Commission finds that it is appropriate to include rate recovery for moving the annual non-union pay structure increases forward to January of each year. The resulting additional compensation for moving the pay structure increase forward will allow WPS to address the issue of facing a more competitive labor market.

De Pere Energy Center

The De Pere Energy Center is a 180-MW simple-cycle natural gas-fired combustion turbine owned by De Pere Energy LLC, a wholly-owned subsidiary of Polsky Energy Corporation. WPS signed a long-term contract to purchase virtually all of the plant's capacity. This plant is expected to be on line by June 1, 1999. Thus, 2000, the second year of the biennial period in this proceeding, will be the plant's first full year of operation. The Commission finds it reasonable to increase the test year revenue requirement in this proceeding to include the incremental cost in the second year of \$7.4 million for the De Pere Energy Center on a normalized basis. Normalization, in this instance, involves increasing the revenue requirement by half of the incremental cost in the second year to allow WPS to recover all of the costs associated with this activity evenly over the biennial period.

Consolidated Water Power

On December 31, 1999, WPS will lose Consolidated Water Power (CWP) as a firm, wholesale customer. This will result in decreased wholesale sales in 2000 which, in turn, will increase the jurisdictional allocation of costs to the retail jurisdiction in 2000. As a result, revenue requirement in 2000 will increase by \$2.4 million over that of 1999. The Commission finds it reasonable that the loss of CWP as a firm, wholesale customer be treated as a known and significant event and that its impact be normalized over both years of the biennial period as previously described.

Kewaunee Steam Generator Replacement

In May 1998, the Commission authorized replacement of the steam generators at Kewaunee in docket 6690-CE-151. Because the co-owners of Kewaunee were not in agreement about whether to proceed with the steam generator replacement, the Commission's decision authorizing replacement triggered a series of other potential changes that has created cost and ownership uncertainties concerning Kewaunee in 2000. The steam generator replacement is projected to take place during the refueling outage scheduled for the spring of 2000. Because of these uncertainties, the Commission finds it reasonable to reopen this docket and to hold a hearing in the fall of 1999 to address the revenue requirement impacts of the issues associated with the steam generator replacement. These issues include the Commission's decision in its July 2, 1998, letter order in docket 6690-CE-151 to change depreciation and decommissioning expense for Kewaunee upon completion of steam generator replacement. In that letter order, the Commission decided to use sum-of-the-years' digits methodology to determine depreciation expense and to extend the period of recovery of Kewaunee depreciation and decommissioning from a period ending in 2002 to a period ending in 2008. In addition, the hearing to be held in the fall of 1999 will address any changes in the ownership of Kewaunee as well as other related asset level changes. The hearing in the fall of 1999 will also address changes in projected fuel expense resulting from changes in the ownership of Kewaunee.

Arbitrator's Decision in Joint Plant Operating Agreement Negotiations

WPS is the operating partner of Kewaunee which it jointly owns with Alliant and MGE. Alliant is the operating partner of Columbia Power Plant which it jointly owns with WPS and MGE. In recent years, these three utilities have shared the indirect costs associated with

operating these plants using fixed fees. The three utilities negotiated for more than two years to determine a new, formula-based methodology for allocating indirect costs, such as administrative and general expenses, but were unable to reach agreement. In October 1997, the three utilities agreed to resolve the issues by use of binding arbitration. The utilities received the arbitrator's decision on September 11, 1998. The decision articulates a new, formula-based methodology for allocating indirect costs among the joint owners on a going-forward basis. In addition, the arbitrator ordered the new methodology to be implemented retroactively to January 1, 1997.

The record in this proceeding includes WPS's recalculation of 1997 cost allocations for Kewaunee as well as Alliant's recalculation of 1997 cost allocations for Columbia. The result of the arbitrator's decision for 1997 is that WPS will be required to refund money to MGE and Alliant for their 1997 allocation of Kewaunee indirect costs. In addition, WPS will be required to pay additional money to Alliant for its additional allocation of 1997 indirect costs for Columbia. The net effect on WPS for the recalculation of the allocation of indirect costs among the joint owners of Kewaunee and Columbia for 1997 is \$1.1 million additional expense.

In addition, WPS and Alliant are the joint owners of Edgewater Unit 4. The two utilities have agreed that this new methodology, including the retroactive component, will be used for allocating indirect costs associated with that unit as well. WPS expects to receive a refund of some amount from Alliant for costs incurred in 1997 and 1998 for the Edgewater 4 Plant.

The Commission finds it reasonable to estimate the net impact of all of these recalculations for 1997 to be a \$1 million increase in expense for WPS and to use this estimate as a reasonable proxy of these recalculations for each of the years for which WPS is seeking to recover such costs. The Commission further finds that the recalculations for 1997 and 1998 are not retroactive because the arbitrator's decision to apply the new methodology to previous periods could not have been anticipated and, thus, the liability was not incurred until WPS received the arbitrator's decision on September 11, 1998. It is reasonable to increase the test year revenue requirement by the Wisconsin retail jurisdictional share of \$2 million to allow WPS to recover the estimated additional \$4 million in expense associated with the arbitrator's decision for the years 1997 through 2000 over the biennial period.

Updated 1999 Forecast for Columbia and Edgewater

Just prior to the hearing in this proceeding, WPS requested recovery of additional forecasted expenses in the test year for its shares of Columbia and Edgewater. Because these updated forecasts were provided by Alliant, the operating partner of those two plants, the timing of the update was out of the control of WPS. The Commission finds it reasonable to increase the revenue requirement by the Wisconsin retail jurisdictional share of \$376,000.

Pulliam 3 Deferral

In 1997, responding to the reliability situation in eastern Wisconsin, WPS requested authority to defer costs associated with bringing Pulliam unit 3 back into service. The unit had previously been placed in "long-term layup status." In its July 3, 1997, letter order addressing the request, the Commission authorized WPS to defer all "out of pocket operating costs associated with bringing Pulliam 3 back into service and its subsequent operation, as well as the

carrying costs associated with all capital expenditures incurred to bring the plant back into service.”

In its filing in this proceeding, WPS requested recovery of its estimate of the total amount that would be deferred before to the start of the test year in this proceeding. Just before the hearing, WPS submitted rebuttal testimony requesting to withdraw this issue from the case and continue deferring the costs until the hearing to be held in the fall of 1999. The reason for the company’s request is that, after Commission staff’s audit was complete, WPS discovered that there were delayed operation and maintenance costs due to an extended outage of the unit in early 1998.

The Commission finds it reasonable for WPS to continue deferring the costs incurred in the 1997-1998 biennial period associated with Pulliam 3 that the Commission authorized for deferral in its July 3, 1997, letter order.

Automated Meter Reading

In this proceeding, WPS requested rate recovery for an automated meter reading pilot which would involve approximately 20 percent of the meters on WPS’s system. The pilot has a rural component which would use a power line communication technology and which would be installed in four rural districts with the highest meter reading costs per meter. The pilot also has an urban component which would employ a radio-based technology in several urban areas. Within the urban portion of the pilot, WPS plans to use a drive-by technology for gathering data for a portion of the urban pilot and a fixed-network technology for the other portion. The pilot would increase the revenue requirement by the Wisconsin retail jurisdictional share of \$973,000.

The Commission finds it reasonable to allow WPS to proceed with its automated meter reading pilot during the biennial period. By so doing, the Commission authorizes WPS to decide whether or not to implement this pilot, pointing out the Commission does not order the company to do so.

Accounting Treatment of Conservation Expenditures

In the company’s last rate proceeding, the Commission authorized WPS to discontinue deferral accounting for conservation investments such as rebates, direct loans, and interest buy-downs beginning in 1997. The Commission also determined in that proceeding that the remaining unamortized conservation investment should be amortized over a five-year period. In this proceeding, the Commission authorized the company to amortize its remaining unamortized conservation investment as of December 31, 1998, over four years.

Annual conservation and weatherization expenditures of \$5,953,825 for electric operations and \$5,104,543 for gas operations are reasonable for each year of the biennial period. All of these expenditures shall be escrowed.

The escrow for the electric utility will have an estimated underspent balance at the end of 1998 of \$664,000. This underspent amount should be returned to electric ratepayers over the biennial period at a rate of \$332,000 per year. The escrow for the natural gas utility will have an

estimated overspent balance at the end of 1998 of \$1,992,000. This overspent amount should be recovered from natural gas ratepayers over the biennial period at a rate of \$996,000 per year. The annual escrowed conservation costs recoverable in rates for each year of the biennial period are \$5,621,825 for electric operations (\$5,953,825 authorized expenditures less \$332,000 underspending amortization) and \$6,100,543 for gas operations(\$5,104,543 authorized expenditures plus \$996,000 overspending amortization).

In addition, the annual amortization of the remaining deferred conservation investments shall be \$4,456,000 for electric operations and \$1,509,000 for gas operations. These amortizations shall be charged to nonescrowed customer service expense in each year of the biennial period.

Learning Center

In the company's last rate proceeding, WPS received its requested recovery of \$1.7 million for its projected 1997 expenditures to establish a learning center for its employees. Actual 1997 expenditures for this activity were \$380,000. In this proceeding, WPS requested recovery of \$875,000 for its learning center. Because its previous forecast for this activity was significantly overstated, the Commission determined a more reasonable forecast of 1999 expenditures for the learning center would be derived from 1998 average monthly expenditures through August. The Commission determined it is reasonable to include recovery of \$505,000, which is the average monthly expenditures incurred through August 1998 on an annual basis, as a reasonable forecast of 1999 expenditures for the learning center.

Certification of New Depreciation Rates and Decommissioning Amounts

In October 1998, the Commission certified new depreciation rates in docket 6690-DU-102. The Commission finds it reasonable that the revenue requirement in this proceeding be adjusted to include the impact of its decision in docket 6690-DU-102.

One provision of the Commission's order in docket 6690-DU-102 is to maintain depreciation and decommissioning expense levels for Kewaunee based on a collection schedule ending in 2002, which was originally certified in the Commission's January 1997 order in docket 05-DE-100. At the time of the Commission's decision in docket 05-DE-100, the Kewaunee steam generators were deteriorating at a rate which made it unlikely that Kewaunee could remain in operation until the end of its operating license in 2013.

In May 1998, the Commission authorized replacement of the Kewaunee steam generators. Because of this, three parties in this proceeding, Citizens' Utility Board, the Wisconsin Industrial Energy Group (WIEG), and the Wisconsin Paper Council (WPC), take the position the Commission should have authorized a test year revenue requirement which includes depreciation expense and decommissioning annuity amounts for Kewaunee based on a collection schedule ending in 2013. They believe that the Commission's previous decision in docket 05-DE-100 was based on the premise that Kewaunee was unlikely to remain in operation until the end of its operating license in 2013. According to these three parties, that premise is no longer valid because WPS is planning to replace the steam generators in 2000.

The Commission finds it reasonable to maintain Kewaunee depreciation expense and decommissioning annuity amounts based on a collection schedule ending in 2002 until the steam generator replacement is completed. The Commission determined that the agreement among the co-owners of Kewaunee about replacing the steam generators involves enough uncertainty to warrant not changing the recovery period until the steam generator replacement has actually occurred. It is reasonable to address the appropriate depreciation method and the appropriate recovery period for Kewaunee depreciation and decommissioning following completion of the steam generator replacement when this docket is reopened in the hearing to be held in the fall of 1999.

Nuclear Plant Decommissioning Expenses

The Commission determined it is reasonable to calculate retail nuclear decommissioning annuities based on a collection schedule ending in 2002 for Kewaunee in this proceeding. WPS's Wisconsin jurisdictional test year income statement includes the Wisconsin jurisdiction's share of retail nuclear plant decommissioning expenses, totaling \$13,827,316. Included in this amount are: 1) cash annuity payments of \$12,263,000, which will be paid to a tax qualified external trust fund for nuclear plant decommissioning; 2) a negative annuity of \$3,957,000 from a nonqualified external trust fund for nuclear plant decommissioning; and 3) \$5,521,316 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.

Accounting for Software Expenditures

In March 1998, the American Institute of Certified Public Accountants' Accounting Standards Executive Committee issued Statement of Position 98-1 (SOP 98-1), Accounting for the Cost of Computer Software Developed or Obtained for Internal Use. SOP 98-1 provides guidance on accounting for the costs of computer software developed or obtained for internal use. During Commission staff's audit in this proceeding, WPS provided its estimate of the costs included in its rate filing for 1999 and 2000 that were reflected as current expenses but which would be capitalized under SOP 98-1.

The Commission finds it reasonable to reclassify the amount identified by the company for 1999 of \$6.9 million from current expense to capital expenditure to comply with this new accounting standard in its determination of the test year revenue requirement.

In addition, WPS identified \$5.1 million included as current expense in its filed calculation of the 2000 revenue requirement that would require reclassification to capital expenditure to reflect SOP 98-1. Because \$1.8 million less would be reclassified from current expense to capital expenditure in the second year of the biennial period, WPS requested known and significant treatment for the \$1.8 million. The Commission finds that the total amount of current expense that will be recognized in the second year of the biennial period as compared to the first year is not sufficiently known to meet the criteria for known and significant treatment.

Discount Rate for Actuarially-determined Employee Benefits

In its filing in this proceeding, WPS requested to update the discount rate used to determine the current expense level for actuarially-determined employee benefits at the time of the submittal of data for the return on equity determination, which is one week prior to the Commission's decision in this proceeding. The Commission agrees that it would be beneficial to all parties to have the best available forecast included in the revenue requirement regarding expenses for actuarially-determined employee benefits. The Commission determined that the appropriate time for WPS to provide its update is at the hearing so that other parties to the case have an opportunity for cross-examination.

At the hearing in this proceeding, WPS provided testimony revising its estimated discount rate from 7.25 percent, included in its filing, to 6.75 percent to reflect current economic conditions. This revision is estimated to increase the total cost of employee benefits in 1999 by \$3.6 million. The Commission finds it reasonable to increase the test year revenue requirement by the Wisconsin retail share of the portion of the \$3.6 million assignable to current expense.

WPS Construction of Combustion Turbine for MGE

On August 31, 1998, WPS and MGE applied for a Certificate of Authority (CA) for WPS to build an 83 MW combustion turbine for MGE to be located at WPS's existing West Marinette Generating Station. The Commission finds it reasonable for WPS to defer all revenue requirement impacts associated with this project, including the fully-allocated cost of WPS's internal labor, as well as carrying costs associated with the expenditures calculated at the weighted cost of capital authorized in this proceeding of 9.76 percent. The appropriate rate treatment of these expenditures will be addressed in the hearing to be held in the fall of 1999.

Request for Renewable Escrow Account

Approximately one week prior to the hearing in this proceeding, WPS submitted testimony proposing a renewable escrow account associated with its green pricing proposal. The escrow would be used to charge the educational and advertising expenses associated with the company's proposed green pricing program as well as the green pricing revenue premiums. The Commission denied the company's request to create a renewable escrow account because the proposal has not been adequately formulated.

Manufactured Gas Production Site Clean-up (MGP clean-up)

In the company's last rate order, docket 6690-UR-110, issued February 25, 1997, the initial amortization of MGP clean-up costs was begun, pursuant to the Commission's finding that prudently incurred MGP clean-up costs are current and legitimate expenses, are reasonably incurred, and, therefore, are subject to recovery from ratepayers. Because the Commission found that neither ratepayers nor shareholders should bear the entire burden of MGP clean-up costs, a sharing of such costs was implemented by means of deferred accounting for such expenses. Under the Commission's approved method, the deferred expenses are reviewed by Commission staff for prudence and prudently incurred expenses are recovered in rates, but with no recovery of the carrying costs on the unamortized balances of the deferred items. This treatment of MGP

clean-up costs was consistent with the Commission policy set forth in docket 6680-UR-108, order dated October 1, 1993.

In this docket, because insurance recoveries exceeded actual costs incurred through 1997, WPS did not include any MGP amortization expense in 1999 revenue requirement. Additionally, WPS did not recommend returning the net recovery dollars (the amount of settlement dollars in excess of clean-up costs so far) to ratepayers, as the majority of the utility's clean-up costs are commencing and will continue into the future. Instead, WPS netted the unamortized balance of deferred MGP clean-up costs against the recovery dollars and has proposed to continue to do so for future MGP clean-up costs until the expenses and insurance recoveries net to zero.

Like WPS, Commission staff did not include any amortization expense in the 1999 income statement and did not recommend returning net settlement dollars to ratepayers at this time. In addition, in order to be consistent with Commission policy that the revenue requirement not reflect the net impact on working capital associated with the unamortized balance of deferred MGP clean-up dollars (i.e., the carrying cost of the unamortized balances of the deferred items), Commission staff computed a "pro forma" or "as if" amortization for working capital purposes. The calculation computes the time value of money related to the recovery dollars that would have been returned to ratepayers over the 1999 test period if the Commission's accounting guidelines on this subject were strictly adhered to. The calculation computes an amount equal to the utility's weighted cost of capital, as estimated in this docket, times the average after-tax amount that would have been amortized, based on the guidelines, and a four year amortization period. In this way, ratepayers receive the time value of money for the recovery dollars that could have been returned to them through an amortization process, and the shareholders receive the overall cash flow benefit of receiving recovery dollars before clean-up costs are incurred. This was an uncontested issue in the proceeding.

The Commission finds net recovery dollars should not be returned to ratepayers at this time because of the reasons cited above. The Commission finds the unamortized balance of deferred MGP clean-up costs through 1997 be netted against the recovery dollars. For future clean-up costs, that process should continue until the expenses and insurance recoveries net to a positive amount. At that time, as reviewed and approved by Commission staff, the previous method of rate recovery for MGP clean-up costs will resume. Additionally, the Commission staff's proposed treatment for net MGP insurance settlements is reasonable. It is appropriate to treat these amounts in a manner consistent with the policy that has been used for MGP costs for other utilities in the state, along with the pro forma amortization of net recovery dollars.

Electric Fuel Costs

The Commission determined a reasonable 1999 test year level of fuel is energy provided of 11,944,388 MWh and net fuel costs of \$145,747,000 will be monitored under the fuel rules. Fuel costs for the second year of the biennial period will be determined during 1999 in a separate proceeding.

In addition to the 1999 test year fuel costs, the Commission authorized WPS's request for deferral and amortization over the biennial rate case period of Federal Department of Energy

Decontamination and Decommissioning Assessments (D&D) uncollected in WPS's rates during 1997 and 1998. The Commission also allowed recovery of carrying costs for the deferral, based on the average weighted cost of capital from the last rate case. The deferrals were granted because the Commission agreed to hold WPS harmless if the U. S. Court of Appeals overturned the decision in Yankee Atomic Electric Company vs. the United States decision. The 1999 test year cost of \$523,000 includes amortized D&D costs of \$458,000 and carrying costs of \$65,000.

The Commission is aware of cost mitigation efforts for the spent fuel disposal fee. Like the recovery of deferred D&D costs, spent fuel disposal fee changes are also supported by the Commission's general practice of granting true-ups for changes in federal tax rates and tax-like assessments. If the cost mitigation efforts result in cost reduction for WPS in the future, the effect should also be deferred.

Monitoring of Fuel Costs

The Commission finds that the resulting reasonable test year fuel cost is \$145,747,000 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 11,944,388 MWh results in an average net fuel cost per kWh of \$0.01220. The test year fuel cost is an average of the monthly fuel estimates for 1999 in Appendix D.

Under Wis. Admin. Code § PSC 116.04, the Commission must establish monthly and annual ranges for monitoring the test year fuel forecasts. The Commission finds the following variance ranges are reasonable for monitoring 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. The method of application of those ranges, established in prior Commission decisions for WPS may continue to be used and applied, using the data in Appendix D for monitoring these ranges.

Hearing to be Held in Fall of 1999

The Commission determined that it is reasonable to reopen this docket and hold a hearing in the fall of 1999 for the purpose of addressing the following issues: 1) the fuel forecast for 2000; 2) the Pulliam 3 deferral; 3) Kewaunee depreciation expense and decommissioning annuity amounts after steam generator replacement is completed; 4) Kewaunee ownership changes and related asset level changes; 5) the reduced fuel costs associated with WPS's increased ownership share in Kewaunee; and 6) the appropriate rate treatment of all revenue requirement impacts associated with WPS's construction of a combustion turbine for MGE, including the fully-allocated cost of WPS's internal labor, as well as carrying costs associated with the expenditures.

Summary of 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 1999 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:

1999 Test Year
Wisconsin Jurisdictional Income Statement

	Electric <u>(000's)</u>	Gas <u>(000's)</u>
Operating Revenues		
Sales of Electricity	\$428,777	-
Sales of Gas & Transportation	-	\$201,568
Other Operating Revenues	<u>22,173</u>	<u>906</u>
Total Operating Revenues	\$450,950	\$202,474
Operating Expenses		
Power Production Expenses	\$195,179	-
Purchased Gas Expense	-	135,551
Transmission & Distribution Expenses	41,022	15,154
Customer Accounts Expenses	14,502	7,418
Customer Services Expenses	19,917	8,413
Administrative & General Expenses	<u>34,817</u>	<u>10,200</u>
Total Operation & Maintenance Expenses	\$305,437	\$176,736
Depreciation Expense	62,512	8,352
Taxes Other Than Income Taxes	21,412	3,860
Income Taxes	14,870	3,325
Investment Tax Credit-Restored	<u>(1,453)</u>	<u>(132)</u>
Total Operating Expenses	\$402,778	\$192,141
Net Operating Income	48,172	10,333
Adjustment to Net Operating Income	<u>879</u>	<u>40</u>
Adjusted Net Operating Income	<u>\$49,051</u>	<u>\$10,373</u>

Net Investment Rate Base

The Commission staff-filed average net investment rate base may reasonably be used for the test year, adjusted for the automated meter reading pilot, the construction of wind generation described below, and for the jurisdictional impact of all adjustments subsequent to the preparation of the Commission staff exhibit.

Construction of Wind Generation

In late September 1998, WPS filed an application for a CA in docket 6690-CE-179 to construct 9.24 MW of wind generation to fulfill its obligation under 1997 Wisconsin Act 204 (Act 204). WPS plans to have this generation installed by June 30, 1999, to qualify for federal renewable energy credits.

The Commission finds it reasonable to increase the test year revenue requirement for the impact of this construction. Since WPS commenced construction of this project before the Commission issued the CA approving construction, which is prohibited under Wis. Stat. § 96.49(2), the Commission finds it reasonable to exclude \$73,248 of the investment from net investment rate base and to deny WPS recovery of that portion of the project which was constructed before Commission authorization. The portion of the project which was constructed before the Commission's issuance of the CA approving construction, \$73,248, should be written off to net income.

In addition, under Wis. Stat. § 196.377(2)(a)(4)(f), WPS is allowed to recover "any costs that are prudently incurred by the utility" in complying with the requirement under Act 204 to construct or obtain renewable generation. The Commission finds it reasonable to allow WPS recovery of the incremental revenue requirement impact in the second year of the biennial period associated with this wind generation, on a normalized basis.

Summary of Net Investment Rate Base

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

1999 Test Year
Wisconsin Jurisdictional Net Investment Rate Base

	Electric (000's)	Gas (000's)
Utility Plant in Service	\$1,480,572	\$269,792
Less: Accumulated Depreciation	<u>1,054,086</u>	<u>133,905</u>
Net Utility Plant in Service	\$ 426,486	\$135,887
Add: Nuclear Fuel Investment-net	18,280	-
Gas Stored Underground	-	14,800
Fuel Stock Inventory	8,639	
Materials and Supplies	16,088	2,601
Decommissioning Trust	147,858	-
Investment in WVIC	442	-
Soo Line Rail Prepayment	288	-
Tomahawk Pulp & Paper	307	-
Less: Customer Advances-net	13,414	591
Amortization Reserve-Federal	<u>895</u>	<u>-</u>
Average Net Investment Rate Base	<u>\$ 604,079</u>	<u>\$152,697</u>

Pro Forma Rate of Return

Estimated operating income for test year 1999 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 (000's)	Gas (000's)
Adjusted Operating Income	\$ 49,051	\$ 10,373
Average Net Investment Rate Base	604,079	152,697
Earned Rate of Return	8.12%	6.79%

Inflation Rates

The Commission finds that reasonable inflation rate estimates are 1.6 percent for 1998 and 2.3 percent for 1999.

Capital Structure

As in prior rate cases, the Commission has determined the average amount of the leveraged Employee Stock Ownership Plan (ESOP) (\$6,988,000 for 1999) should be included when determining appropriate debt and equity levels for WPS, but not in setting utility rates.

In this rate case, Commission staff agreed with WPS's request that the Commission's policy of requiring 47 to 54 percent common equity, on a financial basis, in the WPS capital structure was now inappropriate due to increased business and financial risk. Commission staff and WPS agreed that the new common equity guideline, on a financial basis, should now be one requiring 50 to 55 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. The Commission finds the indicated guideline for 50 to 55 percent common equity in the capital structure, on a financial basis, reasonable.

When consideration is given to the ESOP in the test year, the utility financial capital structure consists of 53.79 percent common stock equity, 5.81 percent preferred stock, 36.71 percent long-term debt and debt equivalents, and 3.69 percent short-term debt. The 53.79 percent common equity, on a financial basis, also falls within the newly adopted common equity guideline.

The Commission determined a reasonable utility capital structure for setting rates consists of 54.22 percent common stock equity, 5.85 percent preferred stock, 36.21 percent long-term debt, and 3.72 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. In its deliberations, the Commission expressed a preference that WPS maintain an amount of common equity in its capital structure, on a financial basis, closer to the higher end of the approved common equity guideline.

Cost of Capital

Applicant, in its initial filing, used an 11.80 percent return on equity. At hearing in this proceeding, WPS requested that a range spanning 12.20 to 12.50 percent should be considered to reflect both increased business risk as well as its superior utility management.

Two intervenors also sponsored testimony on the appropriate return on common equity. The Wisconsin Paper Council indicated its support for an 11.30 percent return on common equity. The Wisconsin Industrial Energy Group indicated that an 11.00 percent return on common equity would be appropriate.

The Commission, in its determination of a fair return on common stock equity, must strike a 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 12.10 percent return on common stock equity to be reasonable and just in this proceeding. In choosing the return on equity, the Commission considered WPS's managerial performance, but it did not make any specific adjustment for such performance.

The Commission finds that the appropriate cost of short-term debt is 4.55 percent. In this proceeding, WPS indicated that it would be issuing \$50,000,000 of 30-year floating lien senior notes. At hearing, Commission staff and WPS agreed that the actual issuance cost should be used if the actual issuance occurred prior to Commission decision. On December 14, 1998, WPS successfully issued \$50,000,000 in new 30-year senior notes at a fixed 6.08 percent interest rate. Since the actual interest rate was known before Commission decision, the Commission determined that the actual issuance interest rate of 6.08 percent should be used for ratemaking purposes and that such a rate is a reasonable long-term debt cost.

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 1999 test year are as follows:

Ratemaking Capital Structure				
	Dollar Amount (000's)	Capitalization Ratios Percent	Annual Cost Rate Percent	Weighted Cost Rate Percent
Utility Common Equity	474,274	54.22%	12.10%	6.56%
Preferred Stock	51,200	5.85%	6.08%	.36%
Long-Term Debt	316,696	36.21%	7.36%	2.67%
Short-Term Debt	<u>32,546</u>	<u>3.72%</u>	4.55%	<u>.17%</u>
Total Utility Capital	874,716	100.00%		9.76%

The weighted cost of capital of 9.76 percent is reasonable for WPS in the 1999 test year. This capital structure and weighted cost of capital produces an economic cost of capital of 14.40 percent and a pre-tax times interest coverage ratio of 5.07 times.

Construction Work in Progress (CWIP)

This issue was not contested. The Commission's present general 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 10.58 percent.

In this proceeding, WPS requested an exception from the general CWIP policy for the Kewaunee steam generator replacement project. WPS specifically requested that it be authorized to accrue AFUDC on 100 percent of CWIP related to the Kewaunee steam generator replacement project. Commission staff indicated that such treatment has been granted to other utilities in the state. In its deliberations, the Commission determined that WPS's AFUDC treatment request for the Kewaunee steam generator replacement project was reasonable.

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. Any future ten-year financial forecast should address how WPS will increase its common equity ratio to maintain financial strength in an increasingly deregulated electric and natural gas industry.

Rate of Return on Rate Base

The composite cost of capital rate, 9.76 percent, is appropriate and necessary to 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 1999 test year is 92.22 percent of capital applicable primarily to utility operations plus deferred investment tax credits. 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, excluding any CWIP associated with the Kewaunee steam generators, 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	9.76%	9.76%
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	92.22%	92.22%
Percent Return Requirement Applicable to Net Investment Rate Base	10.58%	10.58%
Adjustment to Return Requirement on Net Investment Rate Base to Provide a Current Return on 50 percent of the Average Test Year CWIP	.05%	.03%
Adjustment to Return Requirement on Net Investment Rate Base to Provide a Current Return on Capitalized Conservation Investments	.16%	.21%
Adjusted Percent Return Requirement on Net Investment Rate Base	10.79%	10.82%

Revenue Requirement

On the basis of the findings in this order, a \$26,942,000 increase in Wisconsin retail electric revenues and a \$10,280,000 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	8.12%	6.79%
Required Return on Average Net Investment Rate Base	10.79%	10.82%
Average Net Investment Rate Base (000's)	\$604,079	\$152,697
Amount of Earnings Deficiency (Excess) on Average Net Investment Rate Base (000's)	\$16,129	\$6,154
Revenue Deficiency (Excess) to Provide for Earnings Deficiency (Excess) Plus Federal and State Income Taxes at a Combined Rate of 40.135% (000's)	\$26,942	\$10,280

Electric Demand-Side Management (DSM)

WPS's total company electric energy savings goal for 1997 was 94.6 GWh. WPS achieved 58.5 GWh in savings, or 62 percent of the Commission's goal. This is well below the 85 percent minimum established by the Commission as the minimum acceptable level of achievement. WPS's residential sector goal for 1997 was 24.1 GWh. WPS achieved 15.7 GWh, or 65 percent of the Commission's residential electric goal.

WPS's 1999 total company electric savings goals and residential electric savings goals have already been approved by the Commission as a part of the agreement on a state Department of Administration pilot program. This program is described in greater detail below. The approved total company goal for 1999 is 94.6 GWh. Within that total company goal the Commission has set a residential electric goal of 24.1 GWh. As a part of that agreement, WPS will receive credit against its 1998 and 1999 goals. WPS will be credited with 67 GWh in 1998 and 70 GWh in 1999. WPS will remain responsible for 27 GWh in 1998, and 24 GWh in 1999.

As has been the practice, electric total company and electric residential goals for the year 2000, if still appropriate at that time, shall be negotiated between Commission staff and WPS. Any disagreements shall be brought to the Commission for resolution.

In a memo dated November 4, 1997, Commission staff put before the Commission several DSM issues and initiatives. Among other decisions, this memo asked that the Commission approve, reject, or modify utility DSM transition plans for 1998 and 1999. In this memo, Commission staff informed the Commission that WPS's DSM transition plan was not compatible with current Commission policy.

As a result of discussion of this memo at its November 18, 1997, open meeting and at informal meetings held in December, WPS filed a revised transition plan to address the Commission's concerns on January 16, 1998. The revised plan was essentially the same as the earlier plan which Commission staff recommended be rejected by the Commission, but with the addition of several proposed "market preparation" programs. The proposed additional programs would have been fielded by WPS in partnership with local trades and the state Department of Administration (DOA).

Discussions between WPS, DOA, and Commission staff ensued which produced a three-way agreement: a contract between WPS and DOA, statement of principles between DOA and the Commission, and a Commission order to WPS. The Commission determined that these documents would supercede the market preparation proposals contained in WPS's proposed revised transition plan.

These agreements will result in the eventual transfer of \$16,750,000 from WPS's ratepayers to the DOA. Those funds will support two years of energy efficiency market preparation activities overseen by the DOA.

Natural Gas DSM

Energy Savings Goals

WPS's corporate and sector gas energy savings goals have already been approved by the Commission as part of the agreement on a state DOA pilot program. (For more discussion on this program, see the section on electric demand-side management.) The approved corporate goal for 1999 is 3,673,645 gross therms. WPS will be credited with 2,257,388 gross therms as part of the DOA agreement. WPS will remain responsible for saving 1,416,257 gross therms in 1999. This corporate goal includes a low-income gas energy savings goal. (For further discussion on this issue, see the section on low-income energy savings goals.) Corporate and sector gas energy savings goals for the year 2000, if still appropriate, will be negotiated between Commission staff and WPS. Any disagreements will be brought to the Commission for resolution.

The Commission finds that energy savings goals and the process for establishing them, as described above, are reasonable.

Low-Income Energy Efficiency Services

Funding and Delivery Guidelines

In a memo dated November 4, 1997, Commission staff put before the Commission several DSM issues and initiatives. Among other decisions, this memo asked that the Commission respond to documentation about inadequate utility performance in achieving energy savings goals in 1996, including poor performance in the low-income sector. At its open meeting of November 18, 1997, the Commission expressed concern with the current level of funding, energy savings achievement, and comprehensive services provided by utilities to their low-income customers. In response to these concerns, Commission staff proposed a set of funding and delivery guidelines. These guidelines would apply to all utilities and would govern funding and delivery of energy efficiency services to these customers until some other Public Benefits entity can take over responsibility for providing these services. The Commission has already required the adoption of these guidelines in Northern States Power Company's (docket 4220-UR-110) and MGE's (docket 3270-UR-109) rate cases this year.

The Commission finds it reasonable to require WPS to follow these guidelines:

Funding

1. All Wisconsin utilities will maintain and/or increase their level of overall funding for low-income energy efficiency programs, if necessary, to meet their energy savings goals and provide comprehensive services.

2. All Wisconsin utilities will pay up to 100 percent of the costs of delivering and installing energy conservation measures for all eligible low-income customers, if necessary, to complete the work determined to be cost-effective by the state energy audit. Coordination and cost sharing with state weatherization operators should not result in utilities not meeting their energy savings goals or paying less than their share of total program costs.
3. All utility payment for contracted services will be based on dollars per kWh and therm saved. The dollar amount per kWh and therm will be determined, at minimum, by covering 50 percent or more of the contractor's cost of administering and delivering energy efficiency services at the program level.
4. All Wisconsin utilities will establish a goal of holding their internal administrative costs to 15 percent or less of total program costs.

Delivery

1. All Wisconsin utilities will deliver or pay for the delivery of comprehensive energy efficiency services to all eligible low-income customers when determined to be cost-effective by the state energy audit. Comprehensiveness includes non-energy savings benefits like improvements to or maintenance of the health, comfort and safety of the treated building.
2. All Wisconsin utilities will consider contracting with other providers if state weatherization operators cannot deliver and install measures sufficient to achieve energy savings goals and deliver comprehensive services to all eligible low-income customers.

Low-Income Energy Savings Goals

Commission staff proposed that WPS's low-income electric and gas energy savings goals be lowered in 1999 by 43 percent and 22 percent, respectively. The revised goals are 881,335 kWh and 373,645 therms. These goals are already in place informally as of the 1998 program year. None of the responsibility for achieving these savings has been transferred to the DOA pilot. WPS remains responsible for achieving its entire low-income gas and electric energy savings goals. It is expected that WPS will increase its efforts to achieve these less aggressive goals and successfully provide the needed benefits to its low-income customers in the future.

The Commission finds the low-income energy savings goals described above to be reasonable and appropriate. If it is still appropriate to have low-income energy savings goals in 2000, it is reasonable and appropriate that these goals be the same as in 1999.

Low-Income Electric DSM Achievement

As documented in this rate case, WPS has consistently under-achieved its low-income gas and electric energy savings goals for the last five years. In addition, WPS's contract with an

outside program manager did not result in any improvement in its level of achievement in 1997, particularly for electric energy efficiency.

Low-income customers' ability to pay the electric portion of their bill raised some concern. This results because the federally funded Low-Income Home Energy Assistance Program (LIHEAP) does not cover electric costs for low-income customers unless it is their primary heating source. This concern can be mitigated, if not eliminated, by assuring that low-income customers have access to electric efficiency programs to increase their ability to pay their electric bill. Such access to electric efficiency programs can improve if WPS increase its efforts to provide comprehensive electric efficiency services to as many low-income customers as possible.

The Commission finds that it is reasonable and appropriate for WPS to increase its efforts and reallocate financial and programmatic resources to more aggressively pursue achievement of its low-income electric savings goal. WPS should work with Commission staff and its contractors to market these services more effectively to its low-income customers.

Natural Gas Sales Promotion

The Commission found in WPS's last rate case, docket 6690-UR-110, that zero-based budgeting for natural gas sales promotion is appropriate in all future rate cases unless compelling justification is provided by WPS. Commission staff proposed that WPS's gas sales promotion budget be zeroed out for the 1999 and 2000 test years. WPS provided no compelling reason nor documented justification to continue with these programs.

The Commission finds that it is reasonable to zero out WPS's natural gas sales promotion budget for the 1999 and 2000 test years.

Electric Rates

The present electric rates are unreasonable because they will produce inadequate revenue in the test year. Authorized rates and rules, shown in Appendix B, will provide an increase in annual Wisconsin retail electric revenues of \$26,942,000.

Electric Cost-of-Service Studies (COSS)

The fully allocated embedded COSS 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 non-coincident demands and customer counts.

Commission staff submitted three embedded COSS. One embedded study was designed to replicate WPS's embedded study, adjusted to reflect Commission staff's proposed adjustments to rate base, expenses, sales, and revenue requirement. Commission staff's Time-of-Day (TOD) cost-of-service study is a refinement of the allocation approach used by WPS. Commission 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 non-coincident demands rather than upon a minimum system method.

The WIEG believes WPS's cost study overstates the revenue deficiency of the industrial CP-1 and Cp-2 classes. WIEG determined that, to calculate the Cp-1 and Cp-2 revenue deficiency or surplus accurately, the cost study must include the interruptible class demand charge revenues.

The Commission recognizes that the embedded COSS are not precise reflections of 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 COSS or any particular cost-of-service method. It is appropriate to consider all of the cost studies presented in this proceeding 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 provided 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 Rates and Rules

Revenue allocations were proposed by WPS, Commission staff, the WIEG and the WPC. Selection of final class revenue targets, using the COSS 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 rates authorized by the Commission, as shown in Appendix B, include changes in the rate structure of some rate classes and adjustments to meet the final revenue requirement.

The Commission finds the electric rate and rule changes described below to be just and reasonable.

Small Customer Non-Demand Rates

The Commission increased the customer charges for Residential (Rg-1), Optional Residential Time-of-Use Class I Rate Territory (Rg-OTOU) and Small Commercial <100 kW (Cg-1) customers by \$0.50 per month and by \$1.00 per month for the Rural Residential (Rg-2) and Rg-OTOU Class II Rate Territory customer classes. The customer charges remain unchanged for the Farm (Fg-1), Optional Farm Time-of-Use (Fg-OTOU), Small Commercial <100 kW (Cg-2), and Optional Small Commercial Time-of-Use (Cg-OTOU). The Commission increased the energy charges for the Rg-1, Rg-2, Fg-1, Cg-1, and Cg-2 rate classes from its present level of \$0.0547 per kWh to \$0.0586 per kWh. Energy charges for the Rg-OTOU, Fg-OTOU, and Cg-OTOU rate classes are increased from \$0.1030 to \$0.1100 per kWh for on-peak usage and from \$0.0220 to \$0.0245 per kWh for off-peak usage. The Commission determined that maintaining the current customer charge or increasing the customer charge slightly sends customers an appropriate energy conservation signal and avoids the disproportionate rate impacts for low use customers that higher customer charges would cause.

Electric energy charges were generally increased to collect the revenue responsibility allocated to each class.

The Commission increased the rates for space heating (Rc-S1 & Cg-S1) controlled water heating (Gw-1), outdoor lighting (Gy-1, Gy-3, and Gy-4), and street lighting (Ms-1, Ms-3, and Ms-31).

Small Commercial and Industrial Customers (Demand/Energy Rates)

Rate classes Cg-1 and Cg-2 (100-200 kW) and Cg-2 (100-200 kW) are non time-of-use rates while Cg-1 (TOU) includes the same size customers but is an optional time-of-use rate. The Commission kept the customer charges for these rate classes at their current levels. The Commission increased the energy charges for the Cg-1 (100-200 kW) and Cg-2 (100-200 kW) rate classes from \$0.02672 to 0.0274 per kWh and increased the energy limiter charge from \$0.0800 to \$0.0880 per kWh. The demand charge for these classes is increased from \$5.10 to \$5.20 per kW. The Commission kept the on and off-peak energy charges for the Cg-1 (TOU) rate class at its current level. The peak demand charge is increased from \$4.55 to \$4.75 per kW and the customer demand charge is increased from \$0.60 to \$0.65 per kW for this rate class. The standby charge for this class is increased from \$ 1.50 to \$1.70 per kW.

The Commission closed the Cg-1 (100-200 kW) and Cg-2 (100–200 kW) rate classes to new customers. New customers with loads greater than 100 kW and less than 200 kW shall take service under the Cg-1 TOU rate. The Commission directed WPS to eliminate the Cg-1 (100-200 kW) and Cg-2 (100–200 kW) rate classes in the next WPS rate case filing. The Commission authorized WPS to establish a program to contact current customers of the closed rate classes and inform them about the Cg-1 TOU rate and that the customers may be able to save money on it. The program shall include a timeline for installing TOU metering equipment at the Cg-1 and Cg-2 (100 – 200 kW) establishments. The metering would enable an easy transition for eliminating these rate classes in the next rate case and moving customers to the Cg-1 TOU rate. The Commission directed WPS to work with Commission staff in establish this program.

Currently, WPS's Cg-1 TOU rate class has a defined winter and summer season that is different from the Large Industrial Cp-1 and Cp-2 rate classes. The Commission determined that the Cg-1 TOU rate class summer definition shall be June-September and its winter definition shall be October-May, the same as for the Cp-1 and Cp-2 rate classes.

Large Commercial and Industrial Rates.

The Commission made adjustments to the Large Commercial and Industrial (Cp-1 and Cp-2) rate classes with the exception of maintaining the current customer charges. Electricity demand charges were increased for peak demand from \$6.20 to \$6.80 per kW and intermediate demand from \$4.03 to \$5.10 per kW for the Cp-1 rate class. Electricity demand charges were increased for peak demand from \$5.95 to \$6.53 per kW and intermediate demand from \$3.87 to \$4.90 per kW for the Cp-2 rate class. The customer demand for the Cp-1 rate class was increased from \$0.70 to \$0.75/kW. The Cp-2 customer demand remains the same at \$0.25 per kW. Standby service for the Cp-1 and Cp-2 rate classes was increased from \$1.50 to \$1.70 per kW of contracted demand and from \$0.93 to \$1.25 per kW of contracted demand, respectively.

The time-of-use energy charges were increased for both the Cp-1 and Cp-2 rate classes to maintain a close relation to the estimated average five-year marginal cost of energy. The Cp-1 on-peak energy charge was increased from \$0.0246 to \$0.0254 per kWh and the off-peak energy charge was increased from \$0.01523 to \$0.01583 per kWh. The Cp-2 on-peak energy charge was increased from \$0.02386 to \$0.0246 per kWh and the off-peak energy charged was increased from \$0.01453 to \$0.0151 per kWh.

WPS proposed to close the Cp-I2 interruptible tariff to new customers, not allow existing interruptible customer to lower their firm nominations and cap customers' variable interruptible load. WPS also proposed that if the Commission did not authorize these changes, it requested to increase the maximum number of hours of interruption for new interruptible load from the current 300 to 600 hours. The Commission determined that interruptible load is not only needed for WPS's capacity needs, but also for the reliability of Wisconsin's electrical system. The Commission finds that WPS shall continue the current Cp-I2 interruptible tariff for existing customers. However, new interruptible load taking service after the date of this order on the Cp-I2 rate shall have the maximum number of hours of possible interruptions increased from the current 300 to 600 hours. WPS shall work with Commission staff to develop the application of this revision in the Applicant's tariff.

All interruptible credits were left unchanged. The current buy-out provision in the Cp-I2 Interruptible Rider has a limited number of buy-out hours for customers choosing this option. The Commission eliminated the buy-out limitation for the Cp-I2 rider. The Commission added more buy-out levels to the economic buy-out provision. In the case of interruption notices for "capacity related purchases," the customer will be informed that a buy-out is available at buy-out rates (per kWh) of not to exceed \$0.10, \$0.15, \$0.20, \$0.25, \$0.35, \$0.50 plus higher levels continuing in \$0.25 per kWh increments. The amount billed to customers shall be the actual costs incurred by WPS plus an adjustment for gross receipts taxes and line losses.

WPS currently has a Demand Nomination Transfer Agreements Provision that allows interruptible customers to execute special contracts to transfer interruptible load from one customer to another. The provision currently has a minimum load of 1,000 kW that is required to complete a swap. WPS proposed to lower this amount to 200 kW. By lowering the minimum load to 200 kW, this amount will equal the minimum amount of load required to take service under the Cp-I2 rate and will allow smaller customers to participate. This provision was filed with the Commission on an experimental basis. The Commission has eliminated the experimental basis of the Demand Nomination Transfer Agreement Provision and determined to lower to 200 kW the minimum load to participate in the provision.

WPS believes it may have surplus capacity when the De Pere Energy Center becomes operational. The company proposes to set aside 25 MW of available capacity for customers taking service under the Cp-I2 rate. The Commission authorizes WPS to make available to its Cp-I2 customers 25 MW of additional firm capacity at the time the De Pere Energy Center becomes operational. This additional firm capacity becomes available only if the company does not need the capacity to meet the native load requirements. Should WPS receive requests for more than the available 25 MW, each customer would receive additional firm capacity on a pro rata basis.

Buyback Rates

The Commission determined that buyback rates shall remain unchanged.

Green Pricing Program

WPS proposed to use the output of a 9.24 MW wind generation project, mandated by the Legislature in Act 204, for a green pricing program. The Commission determined the 9.24 MW wind generation project is included in the rate base and the cost of this project will be recovered in the authorized retail rates and, therefore should not be part of a green pricing program.

Direct Load Control Riders

The Direct Load Control Riders (Rg-DC, Fg-DC, Cg-DC, and GDC-1) permit interruptions for WPS system generating emergencies or for instances when purchased power is available, but at a cost of \$0.06 per kWh or higher. The riders permit interruptions for 20 minutes per hour for system optimization, testing of the load control system, or short-term system generating emergencies. WPS is now subject to new reliability requirements as defined by MAIN and NERC. To better enable it to meet these new requirements, WPS proposed the 20-minute limitation be increased to one hour. The Commission determined that the Direct Load Control Riders (Rg-DC, Fg-DC, Cg-DC, and GDC-1) may electrically disconnect equipment for a maximum of one hour per day for: 1) system optimization, 2) testing of the load control system, or 3) short term system generating emergencies. The Commission determined the GDC-1 rider, that will expire December 31, 1998, may continue and the experimental status is therefore removed.

Rule Changes

WPS currently charges \$10.00 for checks not honored due to insufficient funds (NSF) or similar reasons (account closed, stop payment ordered, etc). This rate has been in place since 1993 and does not adequately recover the costs incurred by WPS, which have been calculated to equal approximately \$20.00. The Commission determined that WPS may increase its NSF charge to \$20.00 for both checks and electronic transfers not honored by a bank for NSF or similar reasons.

WPS indicated that its cost to re-connect customers has increased significantly since 1982 when current re-connection charges were authorized by the Commission. The Commission determined that the fee for re-connection during regular working hours shall be increased to \$30.00 and the fee for re-connection outside of working hours shall be increased to \$75.00.

WPS proposed a charge for special meter reads. The Commission determined that in situations when a special meter read is requested by the customer with no change in the "customer of record," WPS may apply the following procedures and charges:

- Allow the meter to be read and phoned in by the customer. A consumption cost will then be calculated and provided to the customer.

- WPS will read the meter and issue a special bill. The customer will be assessed a \$28.00 charge for this service. There will be only a single \$28.00 charge if both the gas and electric meters are read at the same time.

WPS does not provide a credit for grounds on the customer side of the meter and this policy is not reflected in its current rules. The Commission authorized WPS to include the provision “Billing Due to Grounds on Customer’s Equipment” as shown in Appendix B in WPS’s service rules to clarify its policy of not providing a credit for grounds on the customer side of the meter.

WPS currently has limitations on the amount of load that can be served from 120/240 volt delta service. The company proposed to add the requirement that new customers shall install dual voltage equipment rated for use at three-phase four wire 120/208 volt or three phase four wire 277/480 volt service in addition to the three-phase four wire 120/240 volt service. The company further proposed that if and when full three-phase service is available, the customer shall convert to either 120/208 volt or 277/480 volt delta service. The Commission determined that WPS rules should be amended to include the revised voltages as shown in Appendix B.

Gas Rate Design

The company proposed several unbundling steps, which the Commission staff supported. First, the company proposed unbundling the telemetering charge and determined the cost to be \$25 per month. The Commission finds this unbundling proposal and the movement to cost of service pricing to be reasonable. In a related proposal, the company proposed reducing the Administration Fee for transportation customers to \$50. Commission staff supported this reduction. The Commission finds this reduction of a potential barrier to competition to be reasonable. Thirdly, the company proposed, and the staff supported, unbundling the costs of acquiring gas for system sales into a separate Gas Acquisition Charge so that transportation customers would not pay for gas supply acquisition services they do not receive. The Commission notes that the order in docket 05-GI-108, Phase I, required Wisconsin natural gas utilities to unbundle gas supply acquisition costs from the cost of providing distribution service and recover these costs in a separate charge. Accordingly, the Commission finds that the company’s proposed Gas Acquisition Charge is reasonable.

The company proposed customer charge increases for the various customer classes which reinforce the economic break-even points between the classes. Commission staff emphasized other rate design objectives.

For the residential class, the company proposed an \$1.00 per month increase to \$5.75. The Commission staff could not reach the \$5.75 level without altering the existing energy charge based on its cost-of-service results, but anticipated that the cost impact of other Commission decisions in this docket would make a \$5.75 charge cost justified. The Commission finds the increase to \$5.75 to be reasonable as a movement toward full cost-of-service pricing.

Similarly, Commission staff opposed the company’s proposed \$42 increase in the customer charge for the medium commercial class from \$81 per month to \$123. Commission

staff proposed a customer charge of \$100 for this class. The Commission finds the increase in this charge to \$100 is reasonable as a movement to full cost-of-service pricing.

For the small commercial class, the company proposed to maintain the current customer charge of \$18 per month. Commission staff testified that the charge was already too high and proposed a decrease to \$14 per month. With a commercial customer charge of \$18, the break-even point between use on the commercial rate versus the residential rate is over 1,800 therms per year. At the same time the average residential use level is less the 950 therms. Since small commercial class and residential class customers have very similar use patterns, an \$18 commercial customer charge means that a small commercial customer must be nearly twice the size of a residential customer before it becomes advantageous to be classified “commercial.” However, being a residential customer is not an option for a small business regardless of its size or usage characteristics. Any “business” must be on the commercial rate, not the residential rate. For example, a small energy efficient group home would have to take service under the company’s commercial rate. Because there is no minimum usage level for the small commercial class, unlike all the larger classes, the break-even point between the residential and small commercial class is a very important aspect of rate design for these similar classes.

The Commission finds that while Commission staff’s arguments have merit, they are not sufficiently persuasive to lower a rate previously found reasonable.

The company raised the issue of what should be the allowable differential generated between adjacent customer classes at the breakpoints. The company testified that breakpoints should promote rate continuity to the greatest extent possible. Commission staff testified that rate continuity at the breakpoints is desirable but is not a necessary feature of a reasonable rate design. The Commission finds that the maintenance of the correct breakpoints between rate classes is a desirable, but not an essential, feature of a reasonable rate design.

For the Coal Displacement Rate class, the company proposed, essentially, that this class make no contribution to the requested increase in revenue requirement. Commission staff proposed that the customer charge be increased from \$950 to \$2,500 per month and that the class be closed to new customers.

The Commission finds that an increase of the customer charge to \$1500 per month from the present \$950 per month customer charge makes adequate progress towards full cost of service pricing.

The company also objected to closing this class because the gas industry is entering a new era of increasing customer options. One of the options the Commission has is to approve narrowly defined tariffs to meet customers’ needs rather than maintaining open classes targeted at alternate fuels, intended to supplant market forces.

The Commission finds that it is reasonable to retain the customer option of a coal displacement rate, however unlikely it is that new customers will use it.

Presently, the company does not explicitly apply a customer charge to either the Interdepartmental or the Power Generation rates. Commission staff proposed that these

company customers be treated like other customers. The company supports Commission staff's proposals. The Commission finds that Commission staff's proposal is reasonable. In an era when Independent Power Producers will be competing with utility power generation, it is important that the company charge itself non-discriminatory rates.

Gas Rates and Rules

The company proposed new rates for the installation of excess flow valves. The Commission staff supports the company's proposal. The Commission finds that the company's proposal will mitigate the consequences of third-parties digging into service lines and causing unrestricted flows of combustibles to vent into the air.

The company proposed increasing the charge for a check returned NSF. Commission staff does not oppose the company's proposal. The Commission finds the Company's proposal will make the company's charge consistent with those of other Wisconsin local distribution companies (LDCs).

The company proposed increasing the reconnection charge. Commission staff and the company negotiated a compromise and now both the Commission Natural Gas Division and Electric Division staff support the company's revised proposal of \$30 during normal working hours and \$75 for after hours service. The Commission finds that the compromise struck marks adequate progress matching costs with cost causation.

The company proposed a new \$28 charge for special meter readings. Commission staff supports the company's proposal. The Commission finds that the company's proposal will match costs with cost causation.

The company proposed to limit the receipt of gas transportation deliveries at the new Conover Station. Commission staff supports the company's proposal. The Commission finds the company's proposal is operationally necessary because the small amount of capacity in question is being used by the company on a dedicated basis which precludes sharing.

The company proposed expanding its authority to declare constraint days as late as 10:00 p.m. on the gas day, because the new intra-day nomination schedule approved by the FERC in order 587-H, and the new GISB "lessor of" rule may impair system reliability and increase costs, to the detriment of core customers and company shareholders. Commission staff testified that this will further burden transportation service. The Commission finds that the constraint authority requested could be applied to customers late in the gas day, when these customers no longer had an opportunity to alter their behavior. The Commission finds that tariff language, as shown in Appendix C, which explicitly makes shippers liable for penalties resulting from changes in intra-day nominations, will adequately avoid gaming of the system by transportation customers and the resulting inappropriate incurrence of pipeline penalties by the company.

In supplemental testimony, the company proposed to change the method used to return wholesale natural gas refunds to customers. Such refunds result from actions taken by the FERC. The company proposed to return wholesale refund dollars to current customers on a

prospective basis via the Purchased Gas Adjustment Clause (PGAC). The current method returns dollars to current and former gas customers based on historical gas usage. Commission staff agreed with the company proposal.

The Commission finds that the company's proposal to return wholesale natural gas refunds resulting from actions by FERC is reasonable. The new language achieves consistency with the method used by other state utilities, along with providing a less burdensome administrative process. Refunds will be returned to current gas customers prospectively, which is as representative as the superceded method.

The company proposed adopting the GISB standard nomenclature regarding intra-day nominations. Commission staff supported the company's proposal. The Commission finds the company's proposal to be reasonable since no system benefits accrue to the company through its use of nonstandard nomenclature.

Intervenors initially raised the issue of non-telemetered transportation service for small volume commercial and residential customers in this case. The Intervenors cited the example of other utilities, notably MGE, which instituted such a program for small commercial customers in an effort to expand choice for smaller volume customers. While the Commission staff encouraged the company to investigate the issue, the company did raise concerns about the necessity for and feasibility of providing a non-telemetered transportation service.

The Commission finds that it is reasonable that the company work with Commission staff to develop a feasible non-telemetered transportation service for small volume commercial and residential customers, as this would be consistent with the Commission's policy of removing barriers to competition. The company shall file with its next rate proceeding a non-telemetered transportation service for small volume residential or commercial customers or present testimony demonstrating why it is not feasible to implement a service, such as MGE's nontelemetered service.

The company proposed to change the notification requirement to move from utility sales service to gas transportation service from the present requirement of notification on November 1st for a change effective November 1st of the following year, to a lesser notice period of January 15 for switches effective the following November 1st. Commission staff agreed with the company. The Commission finds the company's proposal reasonable because this will allow customers greater ease in the movement to gas transportation service without harming the remaining core customers.

Gas Cost-of-Service Studies

The company raised a number of issues relating to the gas COSS presented. The first COSS issue is a fundamental one, whether the Commission staff's use of "bookend" COSS for rate setting is reasonable. Commission staff has presented these types of studies since the early 1980s and successive Commissions have found the use of multiple COSS to be reasonable for setting rates. The company argued that the use of multiple COSS was unreasonable in its last rate case (docket 6690-UR-110). In that docket, the Commission disagreed with the company and found the method reasonable. The Commission again finds that the method is reasonable.

The Commission continues to believe that Method B follows principles laid down by highly esteemed economists in the field and that its use in rate setting is, therefore, reasonable. Accordingly, the Commission finds that all the COSS presented, including the company's, are reasonable for rate setting purposes.

Second, the Commission finds that Commission staff's zero-intercept study is clearly a better fit of the company's Account 376, Mains, data and should be used to derive final rates.

The third COSS issue the company raised is the allocation of Services, Account 380, and Meters, Account 381. Commission staff advocated the use of its standard assumption, a 40/60 percent demand/customer split for Services. The company's study was based on assumptions that allocated 99 percent of the cost of service to the customer component. The Commission finds that while the increased use of plastic pipe deserves consideration, it is reasonable to use a 40/60 percent demand/customer split for services for final rate design.

Inclusion of the Carrying Cost of Storage Gas in the Purchased Gas Adjustment Clause True-up

In its filing, the company proposed to include the carrying cost of gas-in-storage in the purchased gas adjustment clause true-up, which would guarantee one-for-one recovery of such costs. The company position was that it was not reasonable for shareholders to be forced to accept risk of under or over recovery because the use of storage gas is required due to the physical constraints of the ANR system and because the costs are neither within management control or forecastable. Commission staff disagreed with the company proposal and recommended that the current practice of including the carrying cost of storage gas in margin rates was appropriate. Commission staff testified that the company's proposal would not be consistent with the generic order regarding the purchased gas adjustment mechanism, docket 05-GI-106, dated November 8, 1996, the Commission's direction in docket 6690-GR-100 (the ongoing docket implementing a gas cost recovery mechanism for WPS), or with past and present rate treatment for all other Wisconsin gas utilities. In addition, Commission staff recommended that this item was not material enough, when looking at total gas operations, to guarantee one-for-one recovery of these costs, especially with forward-looking rate setting.

The Commission finds that the carrying cost of gas in storage should not be included in the PGAC true-up and should be retained in margin rates. Such costs are legitimate business expenses, but should not be afforded one-for-one rate treatment because of materiality and the regulatory process of forward looking rate setting. Commissioner Farrow dissented.

Environmental Review

This is a Type III action under Wis. Admin Code § PSC 4.10 (3). No unusual circumstances suggesting the likelihood of significant environmental consequences have come to the Commission's attention. Neither an environmental impact statement under Wis. Stat. § 1.11 nor an environmental assessment is required.

Effective Date

The Commission finds, because the test year has already commenced, that it is reasonable this order be effective on the day of mailing. It is also reasonable to specify when a utility must file its new schedules with the Commission and at pay stations, as required under Wis. Stat. §§ 196.19 and 196.21, and when these new schedules will take effect after their filing. WPS shall file the new schedules, as required in Wis. Stat. §§ 196.19 and 196.21, no later than seven days after the effective date of this order. These rate schedules shall take effect on the effective date of this order.

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 \$450,950,000 for the test year ending December 31, 1999, which falls short of the electric revenue requirement by \$26,942,000. Presently authorized rates for WPS's natural gas utility service will produce Wisconsin retail natural gas operating revenues of \$202,474,000 for the test year ending December 31, 1999, which falls short of the natural gas revenue requirement by \$10,280,000. Presently authorized rates would also produce estimated Wisconsin retail electric net operating income of \$49,051,000 and estimated Wisconsin natural gas net operating income of \$10,373,000. Presently authorized rates for electric and natural gas service are unreasonable and unjust because they produce inadequate electric and 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 8.12 percent, which is inadequate.
3. For the gas 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 6.79 percent, which is inadequate.
4. A reasonable and just increase in operating revenue requirement for the test year to produce a 10.79 percent return on WPS's average net investment rate base for Wisconsin retail electric operations is \$26,942,000.
5. A reasonable and just increase in the revenue requirement for the test year to produce a 10.82 percent return on WPS's average net investment rate base for Wisconsin natural gas operations is \$10,280,000.
6. It is reasonable to determine revenue requirement for the biennial period by using 1999 financial projections adjusted for known and significant items forecasted to occur in 2000.

7. It is reasonable for rates in this proceeding to be effective for 1999 and 2000, unless the Commission authorizes new rates as a result of reopening this docket for the hearing to be held in the fall of 1999.

8. It is reasonable for rates in this proceeding to reflect a refund of \$2,558,950 to Wisconsin retail ratepayers for the amount collected over the last biennial period for a Kewaunee mid-cycle shutdown which did not occur.

9. It is reasonable to continue treating the services provided to UPPCO as a utility function in the wholesale jurisdiction. It is also reasonable to assign the revenues and fully-allocated costs associated with these services to the wholesale jurisdiction.

10. It is reasonable to assign the revenues and fully-allocated costs associated with serving wholesale customers who take transmission service under WPS's Open Access Transmission Tariff to the wholesale jurisdiction. It is also reasonable that the fully-allocated transmission rate be used to determine the reduction in the revenue credit to firm customers from the electric interruptible demand charge.

11. It is not reasonable to include estimated executive short-term variable pay plan payments in the test year revenue requirement.

12. It is not reasonable to provide rate recovery for increasing non-union compensation rates and for shortening the non-union pay progressions.

13. It is reasonable to provide rate recovery for moving the annual non-union pay structure increases forward to January of each year.

14. It is reasonable to increase the test year revenue requirement to include the incremental cost in the second year for the De Pere Energy Center on a normalized basis.

15. It is reasonable that the loss of Consolidated Water Power as a firm wholesale customer be treated as a known and significant event and that its impact be normalized over both years of the biennial period.

16. It is reasonable to reopen this docket and hold a hearing in the fall of 1999 to address the revenue requirement impacts of the issues associated with the steam generator replacement, which is scheduled to occur in 2000. These issues include the appropriate level of depreciation and decommissioning expense, any changes in the ownership of Kewaunee as well as other related asset level changes, and changes in projected fuel expense resulting from changes in the ownership of Kewaunee.

17. It is reasonable to increase the test year revenue requirement to allow WPS recovery of the additional expense associated with the arbitrator's decision in the joint plant operating agreement negotiations for the years 1997 through 2000 over the biennial period.

18. It is reasonable to increase the revenue requirement to allow WPS recovery of additional forecasted expenses in the test year for its shares of Columbia and Edgewater.

19. It is reasonable for WPS to continue deferring the costs incurred in the 1997-1998 biennial period associated with Pulliam 3 that the Commission authorized for deferral in its July 3, 1997, letter order. It is also reasonable that this issue be addressed in the hearing to be held in the fall of 1999.

20. It is reasonable to permit, but not require, WPS, in its sole discretion, to proceed with its automated meter reading pilot during the biennial period.

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

22. A demand-side management budget of \$11,058,368 is reasonable for financial planning and in determining the test year revenue requirement. It is also reasonable that all of these expenditures be escrowed.

23. It is reasonable for WPS to amortize the remaining deferred conservation expenditures over a four-year period. It is reasonable that the amortization amount for the test year should be \$4,456,000 for electric operations and \$1,509,000 for gas operations to provide for revenue levelization.

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

25. It is reasonable for WPS to amortize the estimated underspent escrow balance at the end of 1998 for the electric utility over the biennial period at a rate of \$332,000 per year.

26. It is reasonable for WPS to amortize the estimated overspent escrow balance at the end of 1998 for the natural gas utility over the biennial period at a rate of \$996,000 per year.

27. It is reasonable to include recovery of the Wisconsin retail jurisdictional share of \$505,000 in the test year for the learning center.

28. It is reasonable to include the impact of depreciation rates authorized in docket 6690-DU-102.

29. It is reasonable to maintain Kewaunee depreciation expense and decommissioning annuity amounts based on a collection schedule ending in 2002 until the steam generator replacement is completed, as described in the Findings of Fact. It is also reasonable to address the appropriate depreciation method and the appropriate recovery period for Kewaunee depreciation and decommissioning following completion of the steam generator replacement when this docket is reopened in the hearing to be held in the fall of 1999.

30. It is reasonable for WPS to begin accounting for the cost of computer software developed or obtained for internal use according to SOP 98-1 as of the start of the test year. It is

also reasonable for test year revenue requirement to reflect the impact of adopting this accounting standard.

31. It is not reasonable to treat the difference in the amount that would be reclassified from current expense to capital expenditure in the second year of the biennial period as compared with the first year as a result of adopting SOP 98-1 as a known and significant item because it is not sufficiently known.

32. It is reasonable to adjust the test year revenue requirement to reflect WPS's revision of its test year discount rate used to determine the current expense level for actuarially-determined employee benefits from 7.25 percent to 6.75 percent. It is also reasonable that the appropriate time for WPS to provide this update is during the hearing.

33. It is reasonable for WPS to defer all revenue requirement impacts associated with WPS building a combustion turbine for MGE, including the fully-allocated cost of WPS's internal labor, as well as carrying costs associated with the expenditures calculated at the weighted cost of capital authorized in this proceeding. It is also reasonable that the appropriate rate treatment of these expenditures be addressed in the hearing to be held in the fall of 1999.

34. It is not reasonable to create a renewable escrow account.

35. It is reasonable to increase the test year revenue requirement for the impact of the construction of 9.24 MW of wind generation and to allow recovery of the incremental impact in the second year of the biennial period associated with this wind generation on a normalized basis. It is also reasonable to exclude \$73,248 of the investment from net investment rate base and to order WPS to write off that portion of the project to net income.

36. It is reasonable to reopen this docket and hold a hearing in the fall of 1999 for the purpose of addressing the following issues: 1) the fuel forecast for 2000; 2) the Pulliam 3 deferral; 3) Kewaunee depreciation expense and decommissioning annuity amounts after steam generator replacement is completed; 4) Kewaunee ownership changes and related asset level changes; 5) the reduced fuel costs associated with WPS's increased ownership share in Kewaunee; and 6) the appropriate rate treatment of all revenue requirement impacts associated with WPS's construction of a combustion turbine for MGE, including the fully-allocated cost of WPS's internal labor, as well as carrying costs associated with the expenditures.

37. Neither ratepayers nor shareholders should bear the entire burden of MGP clean-up costs, therefore, a sharing of such costs by means of deferred accounting, with recovery in rates of the deferred expenses, after Commission staff review, but with no recovery of the carrying costs on the unamortized balances of the deferred items is reasonable.

38. Net recovery dollars should not be returned to ratepayers at this time, and the unamortized balance of deferred MGP clean-up costs through 1997 be netted against the recovery dollars. Such a process should be continued for future clean-up costs until expenses and insurance recoveries, as reviewed and approved by Commission staff, net to a positive amount. At that time, the previous method of rate recovery for MGP clean-up will resume.

39. The Commission staff's proposed treatment related to the pro forma amortization of recovery dollars as set forth in the Findings of Fact for net MGP insurance settlements is reasonable.

40. The Commission finds the resulting test year fuel costs of \$145,747,000 is reasonable for the purpose of setting just and reasonable rates and reflects 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 11,944,388 MWh results in an average net fuel cost per kWh of \$0.01220. The test year fuel cost is an average of the monthly fuel estimates contained in Appendix D.

41. The Commission authorizes deferred D&D costs and carrying charges to be recovered over the biennial period

42. The reasonable utility ratemaking capital structure consists of 54.22 percent common stock equity, 5.85 percent preferred stock, 36.21 percent long-term debt, and 3.72 percent short-term debt.

43. The reasonable utility financial capital structure, which includes effects of the leveraged ESOP, consists of 53.79 percent common stock equity, 5.81 percent preferred stock, 36.71 percent long-term debt and debt equivalents, and 3.69 percent short-term debt.

44. A reasonable utility financial capital structure, which includes effects of the leveraged ESOP, consists of 50 to 55 percent common stock equity. The 55 percent threshold represents an increase over the Commission's prior 54 percent common equity guideline. The test year's 53.79 percent common stock equity, on a financial basis, is within the new Commission guideline. The utility capital structure will continue to be reviewed periodically.

45. A return on utility common stock equity of 12.10 percent is reasonable for WPS in this proceeding.

46. A short-term debt rate of 4.55 percent is reasonable for WPS in this proceeding.

47. A long-term debt rate of 6.08 percent for the December 14, 1998, issuance of \$50 million of new senior notes is reasonable for WPS in this proceeding.

48. A weighted average composite cost of capital of 9.76 percent is reasonable for WPS in this case.

49. For the test year, 50 percent of average CWIP should earn a current return and the remaining CWIP should earn an AFUDC return of 10.58 percent. The Kewaunee steam generator replacement project is granted an exception allowing WPS to accrue AFUDC on 100 percent of CWIP related to the Kewaunee steam generator replacement project.

50. It is reasonable for all prior dividend restrictions remain in force.

51. 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. The future ten-year financial forecast should address how WPS will increase its common equity ratio to maintain financial strength in an increasingly deregulated electric and natural gas industry.

52. A total company electric DSM goal of 94.6 GWh is reasonable for 1999. As a part of an agreement described in the Findings of Fact, WPS will receive credit against its 1998 and 1999 goals. WPS will be credited with 67 GWh in 1998 and 70 GWh in 1999. WPS will remain responsible for 27 GWh in 1998, and 24 GWh in 1999.

53. It is reasonable for electric total company and electric residential goals for the year 2000, if goals are still appropriate at that time, to be negotiated between Commission staff and WPS. Any disagreements should be brought to the Commission for resolution.

54. It is reasonable and appropriate for WPS to establish corporate and sector gas energy savings goals for the 1999 test year as described in the Findings of Fact. It is reasonable and appropriate for WPS to establish low-income gas and electric energy savings goals for the 1999 test year as described in the Findings of Fact. If gas energy savings goals are appropriate in the 2000 test year, it is reasonable and appropriate for these goals to be negotiated between Commission staff and WPS. Any disagreements should be brought to the Commission for resolution.

55. It is reasonable and appropriate to require WPS to follow the low-income funding and delivery guidelines as described in the Findings of Fact.

56. It is reasonable and appropriate for WPS to increase its efforts and reallocate financial and programmatic resources to more aggressively pursue achievement of its low-income electric savings goal as described in the Findings of Fact.

57. It is reasonable and appropriate to zero out WPS's natural gas sales promotion budget for the 1999 and 2000 test years.

58. The rate and rule changes set forth in Appendix B and C, for retail electric and natural gas utility service will permit the 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, cost-of-service information and utility service rules; and are just and reasonable.

59. It is reasonable to close the Cg-1 (100-200 kW) and Cg-2 (100-200 kW) rate classes to new customers. New customers with loads greater than 100 kW and less than 200 kW shall take service under the Cg-1 TOU rate. WPS shall eliminate the Cg-1 (100-200 kW) and Cg-2 (100-200) rate classes in its next rate case filing. WPS shall work with Commission staff in establishing a program to contact current customers of the closed rate classes and inform them about the Cg-1 TOU rate. The program shall include a timeline for replacing Cg-1 (100-200 kW) and Cg-2 (100-200 kW) meters with TOU metering equipment.

60. It is reasonable to change the Cg-1 TOU rate class summer definition to June-September and its winter definition to October-May.

61. It is reasonable to continue the current Cp-I2 interruptible tariff, however, new interruptible load on this rate shall have the maximum number of hours of possible interruptions increased from the current 300 to 600 hours. WPS shall work with Commission staff to develop the application of this revision in the Applicant's tariff.

62. It is reasonable to eliminate the buy-out limitation for the Cp-I2 rider. WPS shall add the buy-out levels described in the Findings of Fact to its economic buy-out provision.

63. It is reasonable to make the Cp-I2 Demand Nomination Transfer Agreements Provision a permanent provision and lower the minimum load that is required to participate in the provision to 200 kW.

64. It is reasonable for WPS to make available to its Cp-I2 customers 25 MW of additional firm capacity at the time the De Pere Energy Center becomes operational, if the company does not need the capacity to meet native load requirements. Should WPS receive requests for more than the available 25 MW, each customer shall receive additional firm capacity on a pro rata basis.

65. It is reasonable to maintain the current buyback rates as shown in Appendix B.

66. It is reasonable that the cost of a 9.24 MW wind generation project be recovered from all of the Applicant's customers through authorized electric retail rates.

67. It is reasonable that the Direct Load Control Riders (Rg-DC, Fg-DC, Cg-DC, and GDC-1) may electrically disconnect equipment for a maximum of one hour per day for 1) system optimization, 2) testing of load control system, or 3) short term system generating emergencies.

68. It is reasonable that the GDC-1 rider continue on a permanent basis and that the experimental status be removed from the tariff.

69. It is reasonable that the NSF charge be increased to \$20.00 for both checks and electronic transfers not honored by a bank for NSF or similar reasons.

70. It is reasonable to increase the fee for re-connection of gas or electric service during regular working hours to \$30.00 and for re-connection outside of working hours to \$75.00.

71. It is reasonable to make a charge of \$28.00 for special meter reads as outlined in the Findings of Fact.

72. It is reasonable for the company to work with Commission staff to develop a feasible non-telemetered transportation service for small volume commercial and residential customers, as this would be consistent with the Commission's policy of removing barriers to competition.

73. It is reasonable that the carrying cost of gas in storage should not be included in the PGAC true-up and should be retained in margin rates. Such costs are legitimate business expenses, but should not be afforded one-for-one rate treatment because of materiality and the regulatory process of forward looking rate setting.

74. It is reasonable for the company to return wholesale natural gas refunds resulting from actions by FERC. The new language achieves consistency with the method used by other state utilities, along with providing a less burdensome administrative process. Refunds will be returned to current gas customers prospectively, which is as representative as the superceded method.

CONCLUSION OF LAW

THE COMMISSION CONCLUDES:

It has jurisdiction under Wis. Stat. §§ 1.11, 1.12, 196.02, 196.03, 196.19, 196.20, 196.21, 196.37, 196.395, and 196.40 and Wis. Admin. Code ch. PSC 116 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 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 on the date of mailing. WPS shall file the new schedules, as required in Wis. Stat. §§ 196.19 and 196.21, no later than seven days after the effective date of this order. These rate schedules shall take effect on the effective date of this order.
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 shall use a demand-side budget of \$11,058,368 for financial planning and in determining test year revenue requirement and shall escrow all of these expenditures.

6. WPS shall amortize the remaining deferred conservation expenditures over four years. The annual amortization amounts, for each year of the biennial period, shall be \$4,456,000 for electric operations and \$1,509,000 for natural gas operations.

7. WPS shall amortize the estimated underspent escrow balance as of December 31, 1998, for the electric utility over the biennial period at a rate of \$332,000 per year.

8. WPS shall amortize the estimated overspent escrow balance as of December 31, 1998, for the natural gas utility over the biennial period at a rate of \$996,000 per year.

9. WPS shall begin accounting for the cost of computer software developed or obtained for internal use according to SOP 98-1 as of the start of the test year.

10. WPS shall defer all revenue requirement impacts associated with WPS building a combustion turbine for MGE, including the fully-allocated cost of WPS's internal labor, as well as carrying costs associated with the expenditures calculated at the weighted cost of capital authorized in this proceeding.

11. WPS shall write off to net income that portion of the construction of its wind project which was constructed before the Commission's issuance of the CA in docket 6690-CE-179 of \$73,248.

12. WPS shall net any unamortized balance of deferred MGP clean-up costs through 1997 against the recovery dollars. Such a process should be continued for future clean-up costs until the expenses and insurance recoveries, reviewed and approved by Commission staff, net to a positive amount. At that time, the previous method of rate recovery for MGP clean-up will resume.

13. WPS shall account for the pro forma amortization of recovery dollars as set forth in the Findings of Fact for net MGP insurance settlements.

14. A reasonable estimate of fuel costs for each month of the biennial period is attached as Appendix D. Test year rates reflect the monthly fuel cost estimates in the appendix. The fuel costs in the appendix will be used for required monthly monitoring of the fuel cost pursuant to Wis. Admin. Code ch. PSC 116.

15. 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.

16. WPS shall file testimony and exhibits with this Commission in 1999 supporting its positions on the issues to be addressed in the hearing to be held in the fall of 1999 as described in the Findings of Fact. This filing shall be submitted at such time mutually agreed

upon by WPS and Commission staff in order to allow sufficient time for Commission staff and other interested parties to review the information included in the filing, gather additional information necessary for the parties to develop their positions, and prepare testimony and exhibits supporting the parties' positions.

17. WPS shall submit a ten-year financial forecast in all future rate cases before the Commission, as discussed in the Findings of Fact, in which the future ten-year financial forecast addresses how WPS will increase its common equity ratio to maintain financial strength in an increasingly deregulated electric and natural gas industry.

18. WPS shall abide by previously established dividend restrictions.

19. WPS shall maintain 50 to 55 percent common equity on a financial basis in its capital structure.

20. WPS shall adopt the electric total company and residential DSM goals as described in the Findings of Fact. WPS shall negotiate electric total company and electric residential goals with Commission staff for the year 2000, if goals are still appropriate at that time. If an agreement cannot be reached the matter shall be brought to the Commission for resolution.

21. WPS shall establish gas energy savings goals as described in the Findings of Fact.

22. WPS shall establish low-income gas and electric energy savings goals as described in the Findings of Fact.

23. WPS shall negotiate corporate and sector gas energy savings goals with Commission staff for the 2000 test year. If an agreement cannot be reached, the matter shall be brought to the Commission for resolution.

24. WPS shall follow the low-income funding and delivery guidelines as described in the Findings of Fact.

25. WPS shall increase its efforts and reallocate financial and programmatic resources to achieve its low-income electric energy savings goal as described in the Findings of Fact.

26. WPS shall close the Cg-1 (100-200 kW) and Cg-2 (100-200 kW) rate classes to new customers. New customers with loads greater than 100 kW and less than 200 kW shall take service under the Cg-1 TOU rate. WPS shall eliminate the Cg-1 (100-200 kW) and Cg-2 (100-200 kW) rate classes in its next rate case filing. WPS shall work with Commission staff in establishing a program to contact current customers of the closed rate classes and inform them about the Cg-1 TOU rate. The program shall include a timeline for replacing Cg-1 (100-200 kW) and Cg-2 (100-200 kW) meters with TOU metering equipment.

27. WPS shall change the Cg-1 TOU rate class summer definition to June-September and its winter definition to October-May.

28. WPS shall continue the current Cp-I2 interruptible tariff with new interruptible load taking service after the date of this order increasing its maximum hours of possible interruptions to 600 hours. WPS shall work with Commission staff to develop the application of this revision in the Applicant's tariff.

29. WPS shall eliminate the buy-out limitation for the Cp-I2 rider and shall add the buy-out levels as described in the Findings of Fact to its economic buy-out provision.

30. WPS shall make the Demand Nomination Transfer Agreements Provision a permanent provision within its Cp-I2 tariff and lower the minimum load that is required to participate in the provision to 200 kW.

31. WPS shall make available to its Cp-I2 customers 25 MW of additional firm capacity at the time the De Pere Energy Center becomes operational if the company does not need the capacity to meet native load requirements. Should WPS receive requests for more than the available 25 MW, each customer would receive additional firm capacity on a pro rata basis.

32. WPS shall for the Direct Load Control Riders (Rg-DC, Fg-DC, Cg-DC, and GDC-1) electrically disconnect equipment for a maximum of one hour per day for 1) system optimization, 2) testing of load control system, or 3) short term system generating emergencies.

33. WPS shall continue the GDC-1 rider and eliminate the experimental status of the tariff.

34. WPS shall charge a \$20.00 NSF charge for both checks and electronic transfers not honored by a bank for NSF or similar reasons.

35. WPS shall increase the fee for re-connection of gas or electric service during regular working hours to \$30.00 and for re-connection outside of working hours to \$75.00.

36. WPS shall charge a \$28.00 fee for special meter reads as outlined in the Findings of Fact.

37. WPS shall file with its next rate proceeding a non-telemetered transportation service for small volume residential or commercial customers or present testimony demonstrating why it is not possible to implement a service, such as MGE's nontelemetered service.

Docket 6690-UR-111

38. Jurisdiction is retained.

Dated at Madison, Wisconsin, _____

By the Commission:

Lynda L. Dorr
Secretary to the Commission

LLD:MJK:mem:G:\Order\pending\6690-UR-111

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 Wis. Stat. § 227.53. 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 Wis. Stat. § 227.01(3), a person aggrieved by the order has the further right to file one petition for rehearing as provided in Wis. Stat. § 227.49. 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 Wis. Stat. § 227.48(2), 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 9/28/98

APPENDIX A

This proceeding is not a contested case under Wis. Stat. ch. 227, therefore there are no parties to be listed or certified under Wis. Stat. § 227.47. However, the persons listed below participated.

Public Service Commission of Wisconsin
(Not a party but must be served)
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WISCONSIN PUBLIC SERVICE CORPORATION

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CITIZENS' UTILITY BOARD

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WISCONSIN ELECTRIC POWER COMPANY

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WISCONSIN PAPER COUNCIL

by
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ALLIANT - WISCONSIN POWER AND LIGHT CO.

by

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MADISON GAS AND ELECTRIC COMPANY

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by

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Docket 6690-UR-111

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by
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INTERNATIONAL UNION OF OPERATING ENGINEERS
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Docket 6690-UR-111

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