SERVICE DATE
Dec 18, 2014

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates — 6690-UR-123

FINAL DECISION

This is the Final Decision in the application of Wisconsin Public Service Corporation (WPSC) for authority to increase Wisconsin retail electric and natural gas rates in 2015.

Final electric rate changes are authorized consisting of a $24,602,000 annual rate increase for Wisconsin retail electric operations, a 2.5 percent increase. Final natural gas rate changes are authorized consisting of a $15,363,000 annual rate decrease for Wisconsin retail natural gas operations, a 4.3 percent decrease.

Introduction

On April 1, 2014, WPSC filed a request for authority to increase its Wisconsin retail electric rates by $76,809,000, an 8.0 percent increase, and to decrease its Wisconsin retail natural gas rates by $1,624,000, a 0.5 percent decrease, to be effective January 1, 2015. These rate changes are based on a 10.60 percent return on common equity.

On May 6, 2014, a prehearing conference was held to determine the issues to be addressed in this docket and to establish a schedule for the hearing. On September 10, 2014, public hearings were held in Madison, Wisconsin, for members of the general public and for the parties in this proceeding. The Commission received over 300 comments from members of the public as part of the Commission's public hearing process that included the opportunity to submit written comments through the Commission's website or at the hearing, or to testify at the public hearing.

The Commission considered this matter at its open meeting of November 6, 2014.

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

Findings of Fact

1. WPSC is an investor-owned electric and natural gas public utility as defined in Wis. Stat. § 196.01(5)(a), providing electric and natural gas service to north-central and northeast Wisconsin.

2. Presently authorized rates for WPSC's Wisconsin retail electric utility operations will produce total operating revenues of $1,035,304,000 for the test year ending December 31, 2015, which results in an adjusted net operating income of $115,258,000 and an annual revenue deficiency of $24,602,000. Presently authorized rates for WPSC's Wisconsin retail natural gas utility operations will produce total operating revenues of $368,056,000 for the test year ending December 31, 2015, which results in an adjusted net operating income of $37,541,000 and an annual revenue excess of $15,363,000.

3. For the Wisconsin retail electric utility, the estimated rate of return on average net investment rate base of $1,549,917,000 at current rates subject to the Commission's jurisdiction for the test year is 7.44 percent, which is inadequate.

4. For the Wisconsin retail natural gas utility, the estimated rate of return on average net investment rate base of $356,382,000 at current rates subject to the Commission's jurisdiction for the test year is 10.53 percent, which is excessive.

5. A reasonable increase in operating revenue for the test year to produce an 8.39 percent return on WPSC's average net investment rate base for Wisconsin retail electric operations is $24,602,000.

6. A reasonable decrease in operating revenue for the test year to produce a 7.95 percent return on WPSC's average net investment rate base for natural gas operations is $15,363,000.

7. WPSC's filed operating income statements and net investment rate base for the test year, as adjusted for Commission decision, are reasonable.

8. It is reasonable to incorporate the purchased power agreement (PPA) entered into by WPSC after Commission staff's audit into the final revenue requirement.

9. It is reasonable to incorporate the impact of the new rail contract associated with the Columbia jointly-owned power plant for the 2015 test year.

10. It is reasonable to change the dispatch setting for Weston 3 from "economic" to "must-run" on the weekends in the RTSim (economic dispatch) model as doing so does not result in excessive generation from Weston 3.

11. It is reasonable to allow escrow treatment for the American Transmission Company (ATC) and Midcontinent Independent System Operator (MISO) network transmission charges and fees for 2015 and 2016 on a temporary basis.

12. It is reasonable to allow WPSC to base its equivalent forced outage rates (EFOR) on a six-year average versus a five-year average.

13. It is reasonable to incorporate correction of the errors in the calculation of the EFOR in the economic dispatch model.

14. It is reasonable to correct the estimate of test year revenues for Crane Creek wind farm to remove the hours where the Locational Marginal Price (LMP) was negative. It is also

reasonable to use the most recent 12 months of basis differences for calculating Crane Creek revenues.

15. It is reasonable to remove the deferral of $4,087,000 associated with return of the over-collected fuel costs for 2013 as WPSC refunded the remaining over-collection based on August 2014 sales versus refunding it through the test year.

16. It is reasonable in this proceeding to forecast fuel costs based on the New York Mercantile Exchange (NYMEX) natural gas futures prices as of October 15, 2014.

17. A 2015 total company test-year fuel cost of $577.28 million is reasonable.

18. It is reasonable to set a 2015 fuel cost plan-year cost of monitored fuel of $425,386,000 or $30.44 per megawatt-hour (MWh), as shown in Appendix D.

19. It is reasonable to monitor all fuel costs using an annual bandwidth of plus or minus two percent.

20. It is reasonable to allow WPSC to defer any minimum tonnage obligation costs incurred during 2015 for possible future recovery, with the provision that it is required to submit a detailed analysis documenting its efforts to eliminate or minimize these costs when it seeks recovery.

21. It is reasonable to reduce WPSC's test year total company estimated costs of the Integrys Customer Experience (ICE) project by $4.9 million, of which $4.5 million is allocated to the Wisconsin retail jurisdiction.

22. It is reasonable to require WPSC to specifically identify how it reflects estimated savings due to the ICE project as part of future rate case filings.

23. It is not reasonable to include incentive pay plans' costs in test-year electric and natural gas revenue requirements.

24. It is reasonable to authorize Electric and Gas Revenue Stabilization Mechanism (RSM) rates for 2015 for the one-year amortization of the over recovery of revenues generated from 2013 sales.

25. It is reasonable to allow WPSC to defer the actual undepreciated balance of retired plant associated with Pulliam units 5 and 6 and Weston unit 1 and amortize at an amount of $133,000 per month, starting with the actual retirement date, and concluding when the balance is fully amortized.

26. The reasonable level of expensed conservation costs recoverable in rates for the 2015 test year is $16,531,716 for electric utility operations and $3,088,112 for natural gas utility operations. The level for electric utility operations consists of the conservation budget of $15,905,942 and an escrow amortization adjustment of $625,774. The electric escrow adjustment represents the test-year amortization of the projected overspent escrow balance at December 31, 2014, over two years. The level for natural gas operations consists of the conservation budget of $4,732,317 and an escrow amortization adjustment of ($1,644,205). The natural gas escrow adjustment represents the test-year amortization of the projected underspent escrow balance at December 31, 2014, over two years.

27. It is appropriate for WPSC to work with Commission staff to develop metrics for the 2015 customer service conservation activities approved for inclusion in the conservation escrow. If WPSC does not come in for a rate case for a 2016 test year, WPSC shall work with

Commission staff to develop metrics for its 2016 customer service conservation activities by no later than October 1, 2015.

28. It is appropriate to address the return of any remaining RSM energy efficiency funds in WPSC's next rate proceeding.

29. It is reasonable to continue accounting for allowable electric and natural gas conservation expenditures on an escrow basis.

30. It is not reasonable at this time to include an order point directing WPSC to explain ReACT cost overruns in the next rate case.

31. It is reasonable for WPSC to earn a current return on 50 percent of construction work in progress (CWIP) that is not accruing 100 percent AFUDC for the test year.

32. It is reasonable for WPSC to earn a current return on the unamortized balances of the De Pere Energy Center (DEC) premium, Crane Creek revenue normalization and production tax credit deferrals, Fox Energy Center purchased power contract buyout, acquisition adjustment, and contract service agreement (CSA) amortization, the Glenmore Wind Asset retirement deferral, and the deferred tax proration adjustment at the authorized weighted average cost of capital.

33. It is reasonable for WPSC to earn a current return on the unamortized balances of the remaining RSM deferral, Columbia and Edgewater precertification and preconstruction deferral, and the Environmental Protection Agency (EPA) Notice of Violation at the authorized short-term debt rate.

34. It is reasonable to include all uncontested adjustments proposed by Commission staff, the Citizens Utility Board (CUB), and WPSC to WPSC's filed electric and natural gas income statements and average net investment rate bases.

35. A long-term range of 49 percent to 54 percent for WPSC's common equity ratio, on a financial basis, is reasonable and provides adequate financial flexibility.

36. An appropriate target level for the test-year average common equity measured on a financial capital structure basis is 51.0 percent.

37. It is appropriate to limit the amount of equity infusion to the lesser of the amount needed to achieve a test-year average equity ratio, on a financial basis, approximating the target level of 51.0 percent or the amount found not to result in cash or cash equivalent holdings.

38. It is reasonable to remove the Fox Energy Center acquisition contra account balance from the regulatory capital structure.

39. A reasonable estimate of the amount of debt equivalent to be imputed into WPSC's financial capital structure for the test year is $23,225,000, consisting of (a) no debt imputation for advances from affiliated companies, affiliated capital leases, purchased power capital leases, wind-related purchased power agreements, guarantees, underfunded pension and other post-retirement employee benefit plans, and asset retirement obligations; (b) $226,000 related to non-purchased power agreement operating leases; (c) $19,365,000 related to purchased power operating leases; (d) $214,000 related to wind-related land leases; and (5) $3,420,000 related to debt of subsidiary.

40. A reasonable financial capital structure for the test year consists of 51.00 percent common equity, 1.82 percent preferred stock, 42.60 percent long-term debt, 3.76 percent short-term debt, and 0.82 percent debt equivalence for off-balance sheet obligations, including subsidiary debt.

41. It is reasonable to revise WPSC's dividend restrictions based on the capital structure determinations in this proceeding.

42. It is reasonable to require WPSC to submit a ten-year financial forecast in its next rate proceeding.

43. It is reasonable to require WPSC to submit in its next rate proceeding detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent.

44. A reasonable utility capital structure for ratemaking for the test year consists of 50.28 percent common equity, 1.87 percent preferred stock, 43.96 percent long-term debt, and 3.89 percent short-term debt.

45. A reasonable return on utility common stock equity is 10.20 percent.

46. A reasonable interest rate for short-term borrowing through commercial paper is 0.65 percent for the test year.

47. A reasonable interest rate for the $250 million long-term debt to be issued in 2015 is 4.80 percent.

48. A reasonable average embedded cost for long-term debt is 4.94 percent for the test year.

49. A reasonable average cost for preferred stock is 6.08 percent for the test year.

50. A reasonable weighted average composite cost of capital is 7.44 percent.

51. It is reasonable to consider the full range of cost-of-service study (COSS) results presented in the record when allocating test year 2015 electric revenue responsibility.

52. It is reasonable to consider the appropriateness of fixed-charge rates for residential and small commercial customers without first identifying specific class-allocated costs as the basis for these rates. The identification of specific costs would require the Commission to adopt one COSS, which is contrary to long standing Commission practice.

53. It is reasonable to authorize monthly customer charges of $19.00, $25.00, and $40.00 a month for residential, small single phase commercial, and small three-phase customers, respectively.

54. It is reasonable to maintain the Real Time Market Pricing (RTMP) adder rate at the present level of $10 per-MWh.

55. It is reasonable to direct WPSC to meet with the Wisconsin Industrial Energy Group (WIEG) and other interested stakeholders to evaluate the RTMP adder and report back to the Commission no later than April 2, 2015, on the status of these discussions.

56. It is reasonable to annually update the Pg-2A and Pg-2B capacity credit rate so as to be effective June 1, coinciding with the June-to-May MISO planning year, based on the most recent results of the MISO capacity auction.

57. It is not reasonable at this time to implement an avoided transmission cost credit as a part of WPSC's Pg-2A and Pg-2B rates.

58. It is not necessary at this time to direct WPSC to perform a distributed generation (DG) study or contract with a third party to conduct such a study, or to open a separate Commission investigation into DG issues and rate design.

59. It is reasonable to approve the rate changes for electric and natural gas service as shown in Appendices B and C.

60. It is reasonable to approve the changes to the electric extension allowances, miscellaneous clean-up language changes to the electric service rules, the cancellation of the Ms-31 street lighting tariff and modifications to the Ls-1 lighting tariff that are shown in Ex.-WPSC-Beyer-1.

61. It is reasonable to maintain the interruptible credits at the current amounts.

62. It is reasonable to rely on the results of one or more natural gas COSS along with other factors, such as bill impacts, as guides for revenue allocation and rate design.

63. It is reasonable to require WPSC to prepare and submit in its next rate case a COSS that allocates natural gas transmission related capacity costs on each class's coincident Peak Day Demand factor.

64. Presently authorized natural gas rates of WPSC are unreasonable because they produce excess natural gas revenues. It is reasonable to authorize rates for natural gas service for WPSC as shown in Appendix C.

65. It is reasonable to authorize general service rates that result in monthly customer service charges of $17.00, $150, and $620 for residential/standard volume commercial, medium volume commercial, and large volume commercial natural gas customers, respectively.

66. It is reasonable to eliminate WPSC's Coal Displacement Gas Transportation (CDGT) tariff.

67. It is reasonable to reflect changes to the interruption testing and performance provisions found in WPSC's Interruptible Service (GCg-I) and Seasonal Opportunity Sales Service (CgSOS) tariff schedules, and to the to allow for partial curtailment of certain customers in its Customer Attachment, Enlargement and Curtailment procedure (CURT) tariff schedule.

68. It is reasonable to eliminate the tax gross-up of customer contributions from the gas extension rule tariffs.

69. It is reasonable to continue the practice of not allowing the aggregation of customer allowances in the gas extension rule tariffs.

70. It is reasonable to direct Commission staff to investigate, through the issuance of data requests to all gas utilities in Wisconsin, how other gas utilities interpret and apply their gas extension rule tariffs to "first users."

Conclusions of Law

The Commission concludes it has jurisdiction under Wis. Stat. §§ 1.12, 196.02, 196.025, 196.03, 196.19, 196.20, 196.21, 196.37, 196.374, 196.395, and 196.40 and Wis. Admin. Code chs. PSC 113, 116, and 134 to enter a Final Decision authorizing WPSC to place in effect the rates and rules for electric and natural gas utility service set forth in Appendices B and C, subject to the conditions specified in this Final Decision. The rates and rules for electric and natural gas utility service in Appendices B and C are reasonable and appropriate as a matter of law.

Opinion

Applicant and Its Business

WPSC is a public utility, as defined in Wis. Stat. § 196.01(5), engaged in the production, transmission, distribution, and sale of electricity, and in the purchase, distribution, and sale of natural gas in a service area of approximately 11,000 square miles in northeastern Wisconsin and adjacent parts of upper Michigan. Cities that WPSC serves with retail electric service or natural gas service include Green Bay, Marinette, Oshkosh, Rhinelander, Sheboygan, Stevens Point, and

Wausau in Wisconsin, and Menominee in Michigan. WPSC is an operating subsidiary of Integrys Energy Group, Inc. (Integrys), a holding company headquartered in Chicago, Illinois.

Wisconsin Energy Corporation has applied for approval to acquire the outstanding common stock of Integrys. The Commission is processing that application in docket 9400-YO-100. The test-year impacts of that transaction are unknown at this time, and no costs or benefits associated with this transaction are included in the revenue requirement in this proceeding.

WPSC also sells electricity at wholesale rates to other utilities and electric cooperatives for resale. The Federal Energy Regulatory Commission regulates these wholesale sales. WPSC's wholesale rates, therefore, are 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.

Opinion

Revenue Requirement

Fuel Costs

Wisconsin Admin. Code ch. PSC 116 (Fuel Rules) establishes the rate recovery procedures for monitored fuel costs, and requires the Commission to approve a fuel cost plan. In addition to the monitored fuel costs, there are also other fuel costs that are not subject to Fuel Rules monitoring, but are reasonable for inclusion in the revenue requirement in a general rate proceeding. The Commission finds that a reasonable estimate of total company fuel costs (all fuel costs) for the test year is $577.28 million. The Commission finds that a reasonable 2015 fuel cost plan level of monitored fuel costs is $425,386,000, which reflects the costs of generation and purchased energy, minus revenue from opportunity sales of energy and capacity.

The fuel cost plan year monitored fuel cost divided by the authorized level of native requirements of 13,974,835 MWh results in an average net monitored fuel cost per MWh of $30.44.

It is reasonable to monitor WPSC's fuel costs, using a plus or minus 2 percent bandwidth, as provided in Wis. Admin. Code § PSC 116.06(3).

The fuel cost data in Appendix D shall be used for monitoring WPSC's 2015 fuel costs.

Purchased Power Agreement entered into after Commission staff's audit

WPSC requested that it be allowed to incorporate into the final revenue requirement any additional PPAs entered into after Commission staff's audit, but prior to or coincident with the delayed exhibit for the NYMEX update. WPSC entered into one such PPA after Commission staff's audit. WPSC provided the price and MWh associated with the PPA and the corresponding impact on fuel costs. Neither Commission staff nor any party objected to the information provided by the company concerning this PPA. It is reasonable to incorporate this PPA into the authorized revenue requirement.

Rail Obligation Deferral

WPSC filed its revenue requirement with its estimate of rail obligation costs included in its fuel costs. In the Commission's Final Decision in the previous rate case (docket 6690-UR-122) (PSC REF#: 194645), the Commission ordered that the rail obligation costs for 2014 be deferred until after the end of the rail contract in question on December 31, 2015. WPSC stated that it would not oppose deferral treatment for the 2015 costs as well.

WIEG argued in the previous case and the current case that the rail obligation would not be known, nor would it come due until the end of the contract, therefore such costs should be deferred until the end of the contract. Citizens Utility Board (CUB) argued that the contract itself was imprudent and recovery of rail obligation costs should not be allowed.

Both WIEG and CUB agreed that deferring the costs until after the end of the contract was appropriate and that, after the contract is completed and the actual rail obligation costs are known, WPSC should present evidence, in the first proceeding after the end of the contract, that they did all that they could to minimize the amount of the rail obligation costs and that entering into the rail contract when they did was a prudent decision.

As with the Commission's decision in the prior rate case to defer the 2014 test-year rail obligation costs, the Commission finds it reasonable to defer the rail obligation costs for the 2015 test year until after the end of the contract when the Commission may determine whether WPSC's decision to enter into the contract was prudent and whether or not WPSC did everything it could to minimize the rail obligation costs.

New Rail Contract for Columbia

The current rail contract for the Columbia Power Plant expires on December 31, 2014. Wisconsin Power and Light Company (WP&L), the operating partner of the plant, issued a request for proposals for rail service. At the time of the hearing, no agreement had been reached between WP&L and the vendor. Prior to the discussion of the record, WP&L came to terms with the vendor. The new rail contract results in a significant increase in rail costs for 2015. WPSC had forecasted a significant increase in its rail costs for Columbia, but the actual impact was not known until after the hearing. It is reasonable to reflect the actual contract for Columbia rail costs for the 2015 test year.

Weston 3 Dispatch

WPSC dispatched Weston 3 as "must run" on weekdays, but "economic" on weekends. WPSC's rationale for not running Weston 3 as must run on the weekends is that doing so would result in excess generation as compared to recent history. WPSC stated that, if dispatching Weston 3 as must run on the weekends did not result in more generation than that actually achieved in 2006 by Weston 3, they would not object to an adjustment from economic to must-run for Weston 3 on the weekends. When WPSC made the economic dispatch run with Weston 3 being dispatched as must-run on the weekend, the resulting generation was less than the actual generation for 2006. The Commission finds it reasonable to reflect the impact of Weston 3 being dispatched as must-run on the weekends.

Transmission Escrow

WPSC requested escrow treatment for its network transmission charges and credits from ATC and MISO, citing the magnitude of the dollars involved and the uncertainty associated with such costs. CUB did not object to WPSC's request for 2015, but did not want the escrow treatment to extend indefinitely. The Commission notes that the next scheduled rate case for WPSC would be a 2017 test year. Because the Commission does not want to require WPSC to come in for a 2016 test year rate case for the sole purposes of dealing with the transmission escrow, the Commission extends the escrow treatment through 2016, but will revisit the issue for the 2017 test year. Because ATC and MISO have multiple projects in various stages of development and completion, the timing and magnitude of the associated expenditures is uncertain and beyond WPSC's control. As a result, it is reasonable to grant escrow treatment for network transmission service charges and credits for 2015 and 2016. Such treatment is also consistent with how the Commission has handled these costs in other rate case proceedings.

Averaging Period for Equivalent Forced Outage Rate (EFOR)

WPSC has been using a 6-year average for estimating EFORs for the generating units. In the past, these rates have been lower, on average, than the traditional 5-year average, so Commission staff did not propose any adjustments. In this case, the 6-year average appears to result in higher EFORs. WPSC's rationale for using a 6-year period is that major planned outages occur once every 6 years, and using a 6-year average results in there being one major planned outage in each 6-year period. The Commission is persuaded by this reasoning and no intervenor objected to the use of the 6-year average. Therefore, it is reasonable to allow WPSC to use a 6-year average for its EFORs.

EFOR Errors

CUB pointed out some errors in the calculation of EFOR based on GADS (Generating Availability Data System) data. WPSC acknowledged that the items identified were indeed errors and agreed to correct them for the discussion of the record and going forward. It is reasonable to reflect the correction of errors in the computation of the EFOR and its impact on 2015 test year fuel costs.

Crane Creek Revenues

CUB identified two issues with the revenues associated with the Crane Creek wind farm owned by WPSC. The first was that hours with negative LMPs should be excluded from the calculation of revenues as, in those hours, Crane Creek would not be allowed to run. The second issue was that the basis differences used by WPSC in its filing were "old" (calendar year 2012).

WPSC acknowledged those issues and excluded hours with negative LMPs and used more recent basis differences (most recent 12 months of actual). It is reasonable for the Commission to require that the hours with negative LMPs be removed from the revenue calculation for Crane Creek revenues and that the basis differences should be based on the most recent 12 months of actual available at the time of the delayed exhibit.

Deferral of 2013 Underspending in Monitored Fuel

In its rate filing, WPSC included a deferral of $4,087,000 for underspending of monitored fuel costs from 2013 over 2015 and 2016. In the Final Decision in Docket 6690-UR-121, the Commission ordered WPSC to refund the remaining underspending amount in the next month (based on August 2014 sales) as opposed to allowing WPSC to spread the refund over 2015 and 2016. Therefore, it is reasonable to remove the deferral from the 2015 revenue requirement.

NYMEX Update

WPSC requested permission to update fuel costs for forecasts of coal, rail, and natural gas costs on electric fuels costs, purchased power costs, purchased capacity costs, risk management costs, opportunity sales revenues and interruptible revenue credits. WPSC filed a delayed exhibit based on NYMEX futures costs as of October 15, 2014. It is reasonable to update fuel costs for the impact of the information contained in WPSC's delayed exhibit. (Ex.-WPSC-Guntlisbergen-3, PSC REF#: 223478.)

Retirement of power plants

A consent decree with the United States Environmental Protection Agency requires WPSC to repower, refuel or retire Pulliam units 5 and 6 and Weston unit 1 by June 1, 2015. WPSC has decided to retire these units.

The undepreciated balance of retired plant associated with these units on May 31, 2015, is expected to be $11.9 million.[1] The authorized test year revenue requirement includes $1,596,000 of depreciation expense related to these units, or $133,000 per month. The Commission authorizes WPSC to defer the actual undepreciated balance and amortize at an amount of $133,000 per month, starting with the actual retirement date, and concluding when the balance is fully amortized.

ICE project

ICE is a large software project undertaken by Integrys Business Support, LLC (IBS), to standardize the customer information systems across all Integrys companies. The project's benefits include numerous technology upgrades, functional improvements, and enhanced customer data security. WPSC estimates a total of $10.8 million of test-year expenses for the ICE project, including depreciation and return, contractors and consultants, software purchases, and projected labor from new hires.

Cost savings resulting from ICE are not projected to begin until 2016, due to 2015 being a stabilization period, involving a greater amount of billing work, calls to the call center, and collection activity, as well as lower productivity as employees adapt to the new processes.

Commission staff originally proposed disallowing the entire cost of the ICE project, due to lack of demonstrated ratepayer benefit. The Commission finds that information supplied after staff's audit demonstrates the necessity of the ICE project and therefore the Commission will not disallow the entire ICE project costs. Given this demonstrated need, the remaining relevant

[1] The amount would be different if the timing of the retirement varies from May 31, 2015.

question is the amount of these costs which depends upon whether WPSC accurately forecasted the test-year costs associated with ICE.

The ICE project is expected to have an 11-year useful life, yet WPSC forecast this cost to be depreciated based on an expected useful life of 3 to 7 years. The Commission finds that it is reasonable to adjust the depreciable service life to match the 11-year useful life, which reduces WPSC's test year estimated cost by $2 million.

In addition, the Commission finds that it is reasonable to further reduce WPSC's estimate of ICE costs by $2.9 million related to costs for contractors, consultants, software purchases and maintenance. There was a variance equal to this amount between WPSC's test year estimate and its multi-year forecasts of ICE costs and savings. WPSC did not explain this variance until very late in the case, and the explanation was not only untimely, but inconclusive.

Lastly, the Commission finds it reasonable to require WPSC to specifically identify estimated savings due to the ICE project as part of subsequent rate case filings. Such a requirement would make it more likely that ratepayers would realize the cost saving benefits of ICE.

Incentive Compensation

WPSC requested recovery of its non-executive "pay-at-risk" (a/k/a incentive) pay plan costs. WPSC provided the results of a compensation study to support its claim that its total compensation, including incentives, is reasonable compared to other utilities. Commission staff made adjustments to this comparison to properly weight the study results by numbers of employees, and to reflect lower cost of labor in Green Bay than the national average. Based on these adjustments to the study, Commission staff eliminated non-executive incentive pay plan costs from revenue requirement.

The Commission accepts staff's adjustment. Not only is disallowance of incentive pay consistent with recent Commission decisions, more importantly, after removing these incentives from WPSC's total compensation and reflecting Commission staff's adjustments to the study, WPSC's compensation remains slightly above the market. Moreover, the cost of labor and the cost of living are both lower in Green Bay than the national average and these lower costs have a bearing on the reasonableness of WPSC's compensation package. WPSC has not demonstrated that including non-executive incentive pay in the revenue requirement is necessary to allow it to retain employees, or otherwise pay market rates for its employees. Therefore, it is unreasonable to include these costs in the revenue requirement.

Other Deferrals

As a result of the ratemaking process, and with reasonable regulatory assurance of future cost recovery, utilities sometimes include allowable costs in a period other than the period in which those costs would be charged to expense by an unregulated enterprise in accordance with generally accepted accounting principles. These differences usually relate to the timing of the recognition of a cost. The result of these timing differences is the creation of deferred accounts.

The Commission's policy on deferred accounts is set forth in the Commission's Statement of Position, SOP 94-01. Appendix E is a list of those deferred accounts approved for WPSC, the amortization period, and the amount of Wisconsin jurisdictional 2015 test-year amortization expense. It is appropriate to treat all amortizations as normal test-year expenses by recording the full amounts in the test year.

Electric and Gas Revenue Stability Mechanisms (RSM)

The RSMs are applicable only to the residential, small commercial and medium-size commercial classes and were in place from 2008 through 2013. Actual 2013 electric and natural gas sales were higher than the test year forecast, necessitating a refund. A two-year amortization of the 2013 RSM refunds was proposed because it would mitigate rate impacts better than a one-year amortization. However, a one-year amortization would return customers' overpayments sooner and would likely do so in a more equitable manner.

Consistent with past practice, the Commission approves a one-year amortization. For test year 2015, applicable electric utility customers are credited with $4.3 million of RSM-related over-collections of 2013 sales. For test year 2015, applicable natural gas utility customers are credited with $8.0 million of RSM-related over-collections of 2013 sales.

Energy Efficiency

Customer Service Conservation

WPSC's proposed 2015 natural gas and electric customer service conservation (CSC) activities are essentially the same as provided to its customers in the recent past. These activities include providing energy efficiency information and education through field and call center staff, advertising campaigns and bill inserts, newsletters, K-12 Energy Education, and annual memberships and sponsorships.

In its Order in docket 5-BU-102, dated July 13, 2012 (PSC REF#: 168310), the Commission provided guidance regarding appropriate CSC activities. The Commission defined CSC activities as "those activities and services that a utility provides its customers to: (1) help them understand and control their energy use and bills; (2) create customer awareness of energy efficiency and its value; (3) provide information and assistance related to energy efficiency topics; or (4) encourage and assist customers to take advantage of other services provided by Focus on Energy and federal and state energy programs. Fifty-one percent (51%) of an activity or service must be dedicated to energy efficiency in order to meet the definition of CSC." Based on this guidance, the Commission finds WPSC's proposed 2015 CSC activities and services to be appropriate.

Metrics of Success

WPSC did not propose metrics of success for its CSC activities. The Commission's Order in docket 5-BU-102, dated July 13, 2012 (PSC REF#: 168310), requires utilities to work with Commission staff to develop metrics for their CSC activities and services to ensure CSC funds provide a useful service to ratepayers. The Commission determines that it is appropriate for WPSC to work with Commission staff to develop metrics of success for the 2015 CSC activities approved by the Commission. It is appropriate that these measures of success be developed by January 31, 2015. The Commission also concludes that it is appropriate, should WPSC not come in for a rate case for a 2016 test year, for WPSC to work with Commission staff to develop metrics of success for its 2016 CSC activities by October 1, 2015.

Unspent RSM Energy Efficiency Funds

As a result of the Commission's Order in docket 6690-UR-119, as part of the RSM pilot WPSC contributed additional dollars to Focus on Energy to fund energy efficiency community pilots and WPSC territory-wide energy efficiency programs. The community pilots ended on December 31, 2012, while the territory-wide programs continued through December 31, 2013. While the programs funded by the additional contributions to Focus on Energy were discontinued, there continued to be expenditures for the territory-wide programs in 2014. A small number of incentives remained to be paid for projects installed before the programs' deadline. Additionally, program evaluation was completed in 2014. As of May 1, 2014, more than $1.5 million of the RSM energy efficiency funds remained unspent. The Commission determines it appropriate to address the return of unspent RSM energy efficiency funds in WPSC's next rate proceeding, by which time the books for the RSM related energy efficiency programs will be closed out.

Conservation Budget and Escrow Adjustment

WPSC filed a proposed 2015 conservation budget of $20,638,259, with $15,905,942 allocated to electric operations and $4,732,317 allocated to natural gas operations. Commission staff's analysis of conservation expenses included reviewing the proposed test-year conservation expenditures, forecasting the over-spent balance in the conservation escrow at the beginning of the test year, and reviewing WPSC's forecasted amortization expense associated with previously escrowed conservation expenditures. As a result of this analysis, Commission staff forecasted a $1,251,549 over-spent balance at December 31, 2014, for electric operations and an ($3,288,410) under-spent balance at December 31, 2014, for natural gas operations. Commission staff's forecasted revenue requirement includes the amortization of the estimated over-spent and under-spent balances over the two years beginning in 2015, or $625,774 test-year amortization of the estimated electric over-spent balance and ($1,644,205) test-year amortization of the estimated natural gas over-spent balance.

The reasonable level of expensed conservation costs recoverable in rates for the 2015 test year is $16,531,716 for electric utility operations and $3,088,112 for natural gas utility operations.

The level for electric utility operations consists of the conservation budget of $15,905,942 and an escrow amortization adjustment of $625,774. The electric escrow adjustment represents the test-year amortization of the projected overspent escrow balance at December 31, 2014, over two years. The level for natural gas operations consists of the conservation budget of $4,732,317 and an escrow amortization adjustment of ($1,644,205). The natural gas escrow adjustment represents the test-year amortization of the projected underspent escrow balance at December 31, 2014, over two years.

ReACT Project

In docket 6690-CE-197, the Commission authorized WPSC to construct, install, and place in operation a new multi-pollutant control technology known as ReACT™ at Weston unit 3. (PSC REF#: 183440, PSC REF#: 184440.) Since that approval, the costs of the project have increased. Since this project is 100 percent Allowance for Funds Used During Construction (AFUDC), WPSC is not seeking recovery of any of those costs in this proceeding. The costs will be included in the next rate case filing. CUB proposed that WPSC be required to give a detailed explanation of the project cost variance in their next rate case filing.

The Commission finds that no specific ReACT order point is necessary in this case. Such an order point would be premature. WPSC is not seeking any ReACT cost recovery in this proceeding, and the issue will be fully explored in detail in the rate case in which WPSC first seeks cost recovery for the project.

Summary of Operating Income Statements at Present Rates

In addition to the findings regarding the specific items discussed in this Final Decision, all other uncontested adjustments proposed by Commission staff, WPSC, and CUB to WPSC's filed operating income statements are appropriate.[2] Accordingly, the estimated Wisconsin retail electric and natural gas utility operating income statements at present rates for the 2015 test year, which are considered reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

	Electric (000's)	Natural Gas (000's)
Operating Revenues		
Sales of Electricity	$977,439	$ ---
Sales of Natural Gas Including Transportation	---	358,746
Other Operating Revenues Including Opportunity Sales	58,036	9,310
Other Income - Before Tax	(171)	---
Total Operating Revenues	$1,035,304	$368,056
Operating Expenses		
Fuel and Purchased Power	$514,838	$ ---
Purchased Gas Expense	---	229,138
Other Production Expenses	75,149	4,676
Transmission Expenses	160	977
Distribution Expenses	48,153	23,528
Customer Accounts Expenses	13,237	9,704
Customer Service & Sales Expenses	24,125	5,798
Administrative & General Expenses	58,620	15,204
Total Operation & Maintenance Expenses	$734,282	$289,025
Depreciation Expense	86,665	17,240
Amortization Expense	9,527	-174
Taxes Other Than Income Taxes	38,167	5,260
Income Taxes	51,415	19,115
Total Operating Expenses	$920,056	$330,466
Net Operating Income	$115,248	$ 37,590
Adjustments to Net Operating Income	10	-49
Adjusted Net Operating Income	$115,258	$ 37,541

[2] One such uncontested item was to include WPSC's updated estimate of pension and benefit costs relating to the return on pension assets and the discount rate assumption, including the asset valuation, in the electric and natural gas revenue requirement. In the last several WPS rate cases, the Commission has allowed WPSC to provide an update of its pension and benefits costs prior to the Commission decision that included an update of both the discount rate and updated pension asset valuation information. In connection with the Commission's decision in docket 3270-UR-120, the Commission has determined that it is reasonable for Commission staff to review the issue of inclusion of pension and benefit updates and their prediction record in the next round of rate cases for all investor-owned utilities.

Average Net Investment Rate Base

All uncontested Commission staff adjustments to WPSC's filed average electric and natural gas net investment rate bases are appropriate. Accordingly, the estimated Wisconsin retail electric and natural gas utility average net investment rate bases for the 2015 test year, which are considered reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

	Electric (000's)	Natural Gas (000's)
Utility Plant in Service	$3,180,820	$760,352
Less: Accumulated Reserve for Depreciation	1,687,646	431,873
Net Utility Plant	$1,493,174	$328,479
Add: Natural Gas in Storage	---	26,596
Fuel Inventory	33,408	---
Materials and Supplies	28,502	3,038
Other Investments - net of tax	762	---
Less: Customer Advances	5,929	1,731
Average Net Investment Rate Base	$1,549,917	$356,382

Pro Forma Rate of Return

The adjusted net operating income at present rates for purposes of this proceeding for the test year ending December 31, 2015, results in a rate of return on average net investment rate base of 7.44 percent for Wisconsin retail electric utility operations and 10.53 percent for Wisconsin retail natural gas utility operations.

Financial Capital Structure and Dividend Restriction

The long-term range for WPSC's common equity ratio, on a financial basis, is 49 to 54 percent common equity. Historically, the capital structure for WPSC has been balanced with equity infusions from and special dividends to Integrys to maintain a test-year average equity near a target level within the approved range. An appropriate target level for the test-year average common equity measured on a financial basis is 51.0 percent, provided that the amount of the equity infusion will offset new indebtedness and does not result in cash or cash equivalent holdings. This target level is consistent with the 49 to 54 percent range established by the Commission.

In calculating capital structures, on a financial basis, this Commission has imputed debt associated with obligations not reported on balance sheets. The imputed debt results in additional costs to ratepayers because the utility is required to add sufficient common equity to maintain its target equity level, and the higher return earned on the additional equity increases the weighted cost of capital. In addition, imputing debt for off-balance sheet obligations is not a common practice of other state utility commissions. The Commission is not obligated to adopt the risk assessment of an outside rating agency and will independently examine off-balance sheet obligations, based on its assessment of risk.

To independently examine off-balance sheet debt obligations, it is reasonable to require that WPSC submit detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent. The information shall include, at minimum: (1) the minimum annual lease and PPA obligations; (2) the method of calculation along with the calculated amount of the debt equivalent; and (3) supporting documentation, including all reports, correspondence and any other justification that clearly established Standard & Poor's (S&P) and other major credit rating agencies' determination of the off-balance sheet debt equivalent, to the extent available, and publicly available documentation when S&P and other major credit rating agencies documentation is not available.

For the test year, the Commission finds it reasonable to impute in aggregate $23,225,000 of debt equivalent. Of this amount, $226,000 is relating to non-purchased power operating leases and $3,420,000 of subsidiary debt related to WPSC's subsidiary, WPS Leasing. The operating lease imputation is based on 100 percent of the present value of the payment streams, while the subsidiary debt is the forecasted average principal outstanding for the test year.

An additional $19,365,000 of imputed debt relates to PPAs and includes approximately $18,244,000 for debt equivalence for contracted capacity payments. The imputations are based on a 40 percent risk factor applied to the present value of the payment streams. An additional $1,121,000 of debt equivalence is associated with calculated proxy capacity payment associated with energy contract minimums and a 25 percent risk factor adjustment. Use of a 25 percent risk factor reflects the risk associated with the recovery of this expense through the fuel clause.

Consistent with its treatment in previous dockets, the Commission determined that no debt imputation should be included for wind, parallel generation, and renewable portfolio standard PPAs. The Commission determines that the debt imputation for the wind related land leases shall be based on the lesser of the present value of the payments, assuming continued operation of the wind turbines and the present value of the termination payments if the operation is discontinued. For the test year, one year of lease payments was treated as the proxy termination payment with a present value of $214,000.

Lastly, neither WPSC nor Commission staff included debt imputation associated with obligation categories of advances from associated companies, affiliated capital leases, purchased power capital leases, guarantees, underfunded pension and other post-retirement employee benefit plans, or asset retirement obligations. For each of the above categories, either WPSC does not have any obligations or this Commission has previously determined not to include debt imputations for these categories.

Incorporating the above debt equivalences for off-balance sheet debt obligations and other Commission determinations, WPSC's financial capital structure for the test year will consist of 51.00 percent common equity, 1.82 percent preferred stock, 42.60 percent long-term debt, 3.76 percent short-term debt, and 0.82 percent debt equivalence for off-balance sheet obligations, including subsidiary debt. The 51.00 percent common equity, on a financial basis, is consistent with the common equity target.

Assessing the reasonableness of WPSC's capital structure depends upon three important principles. First, capital structure decisions must be based on WPSC's needs, not on the needs of the non-utility operations of the holding company. Second, the capital structure should provide adequate flexibility for WPSC and the Commission to allow proper utility investment now and in the future. Third, the dividend policy of WPSC should be similar to typical electric utility dividend practices as long as WPSC is below the estimated test-year common equity ratio.

Generally, under Wis. Stat. § 196.795, the utility's capital needs must take precedence over non-utility needs if ratepayers are to be protected. The identification of utility needs goes beyond foreseeable needs. WPSC must have flexibility to finance both foreseen and unforeseen capital requirements.

In previous dockets, the Commission recognized the need to protect ratepayers and to ensure that utility needs are placed before non-utility needs in capital structure and dividend policy choices. Consequently, WPSC shall not pay, without Commission approval, normal dividends greater than 103 percent of the prior year's common dividend. WPSC shall notify the Commission if any special dividend is contemplated. No special dividend that might cause the common equity, on a financial basis as calculated in this Final Decision, to drop below the projected calendar year average of 51.00 percent or the dollar amount of equity reflected in the test year, is permitted without prior Commission approval.

Ten-Year Financial Forecast

WPSC's ten-year financial forecast is useful to the Commission and shall be submitted in future rate cases. The ten-year forecast can be combined with other business risk information to assess capital structure needs and rate of return requirements.

Regulatory Capital Structure and Cost of Capital

As in the previous rate case docket, in order to arrive at the common equity amount for WPSC's regulatory capital structure, Commission staff deducted WPSC's investment in common equity of the ATC, net of deferred income taxes associated with transmission assets transferred to ATC, along with other non-utility items, from booked common equity. In its filing, WPSC included an $11,559,218 contra account balance for the Fox Energy Center acquisition in its regulatory capital structure. Commission staff removed the contra account balance during its audit, and the removal was uncontested. Consequently, a reasonable utility rate making capital structure for the purpose of establishing just and reasonable rates for the test year consists of 50.28 percent common equity, 1.87 percent preferred stock, 43.96 percent long-term debt, and 3.89 percent short-term debt.

Short-Term Debt

WPSC's test-year capital structure contains approximately $105 million of short-term debt in the form of commercial paper. A reasonable estimate of WPSC's average cost of short-term commercial paper debt for the test year is 0.65 percent. The forecast is based on the average of commercial paper rate estimates provided by the *Blue Chip Financial Forecasts* newsletter. This is a reasonable and objective method of determining WPSC's short-term debt costs.

Long-Term Debt

WPSC's test-year long-term debt includes a financing of $250 million 30-year debt forecasted for November 2015. A reasonable estimate for the cost of the issuance is 4.80 percent. The resulting embedded cost of long-term debt is 4.94 percent for the test year.

Preferred Stock

The average cost of preferred stock is 6.08 percent for the test year.

Return on Common Equity

The principal factor used to determine the appropriate return on equity is the investors' required return. Authorized returns less than the investors' required return would fail to compensate capital providers for the risks they face when providing funds to the utility. Such sub-par returns would make it difficult for a utility to raise capital on an ongoing basis. On the other hand, authorized returns that exceed the investors' required return would provide windfalls to utility investors as they would receive returns that are in excess of the necessary level. Such high returns would be unfair to utility consumers who ultimately pay for those returns.

In reaching its determination as to the appropriate return on equity, the Commission must balance the needs of investors with the needs of consumers, with due considerations to economic and financial conditions along with public policy considerations. When making this decision, the Commission exercises its legislative function in setting policy based upon its balancing of these factors. The law recognizes the great degree of discretion exercised by the Commission in making such decisions and affords such decisions great weight deference. The use of this discretion is also necessary because the investors' required return cannot be measured with precision. Because that return cannot be measured precisely, determining the appropriate return on equity is typically one of the more contested issues in a rate proceeding such as this one.

In this proceeding, WPSC's application requested an increase in its current authorized return from 10.20 percent to 10.60 percent. WPSC's financial witness supported a return of 10.60 percent. Commission staff suggested that the appropriate return on equity be set somewhere in the range from 10.00 percent to 10.20 percent and used 10.20 percent in the revenue requirement, based on an anticipated settlement with parties which did not materialize. Commission staff testified that the rate design subsequently filed by WPSC shifted $114 million of variable revenue to fixed revenue and that the reduced revenue volatility supported a reduction in the authorized return on equity. CUB, Environmental Law and Policy Center (ELPC), and RENEW Wisconsin all supported reducing the return on equity to reflect the lower revenue volatility. The revenue impact for each 10-basis points is approximately $1,500,000 for electric and $300,000 for natural gas.

Given the above-mentioned considerations, the Commission finds that the balance is struck most reasonably in this proceeding by authorizing a return on equity capital of 10.20 percent.[3] While the parties argued that a lower rate of return is appropriate based upon the Commission's approval of higher customer charges in certain customer classes, the Commission is not convinced the record in this case establishes a direct, identifiable reduction in an investor's

[3] The dissent criticizes the Commission for authorizing an ROE in excess of what Commission staff's models suggest are the appropriate ROE. The Commission has a long standing practice of refusing to mechanically apply any particular ROE model. Both Commission staff and the dissent recommend ROE ranges in excess of those particular models. The record supports a wide range of reasonable outcomes with respect to ROE. The Commission finds, however, that the record does not support a specific basis point reduction as a direct result of an increase to fixed customer charges.

required return. Absent such a showing, the Commission is also not persuaded that there are sound public policy reasons at this time for setting a lower return on common equity simply because the Commission has determined an increase in the amount of fixed charges is appropriate. There have been instances when the Commission has lowered the return on equity when fixed charges were increased, but there also have been instances where the return of equity has been reduced without any concomitant change to fixed charges. It is important to first understand what effect, if any, fixed charges have on a company's earnings, and sales and other risk factors before the Commission, as a matter of policy, determines it is appropriate to reduce return on equity as a matter of course when fixed charges increase. A 10.20 percent return is reasonable and should allow WPSC to attract capital at reasonable terms without unduly burdening consumers with excessive financing costs.

Commissioner Callisto dissents.

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

	Amount	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	$1,373,692,893	50.28%	10.20%	5.13%
Preferred Stock	51,188,200	1.87%	6.08%	0.11%
Long-Term Debt	1,201,141,667	43.96%	4.94%	2.17%
Short-Term Debt	106,114,603	3.89%	0.65%	0.03%
Total Utility Capital	$2,732,137,363	100.00%		7.44%

The weighted cost of capital of 7.44 percent is reasonable for WPSC for the test year. It generates an economic cost of capital of 10.95 percent and a pre-tax interest coverage ratio of

4.98 times on the regulatory capital structure, and 5.05 times on the test-year financial capital structure.

Rate of Return on Rate Base

The 7.44 percent composite cost of capital must be translated into a rate of return that can then be applied to the average net investment rate base and used to compute the overall return requirement in dollars. The estimate of WPSC's average net investment rate base plus CWIP for the test year is 93.94 percent of capital applicable primarily to utility operations plus deferred investment tax credits. This estimate reflects all appropriate Commission adjustments, and is a reasonable and just factor for use in translating the composite cost of capital into a return requirement applicable to the average net investment rate base.

To allow a test-year current return on the average CWIP balance not accruing AFUDC at 100 percent, an adjustment must be added to the return on net investment rate base. Given WPSC's financing and cash flow requirements in the test year and the forecasted amount of construction activity, the Commission finds it reasonable to allow a current return on 50 percent of CWIP that is not accruing 100 percent AFUDC for the test year.

Consistent with prior Commission decisions, it is reasonable to include adjustments to the return on net investment rate base to allow a current return on the unamortized balances of the De Pere Energy Center premium and to include adjustments for Crane Creek revenue normalization, deferred production tax credits, less depreciation; Fox Energy Center purchased power contract buyout, acquisition adjustment and CSA amortization; the Glenmore Wind Asset retirement; and the deferred tax proration adjustment required in federal tax normalization rules when setting rates based on a forecasted test year, at the authorized adjusted weighted average cost of capital. In addition, it is reasonable to include adjustments to the return on net investment rate base to allow a current return on the unamortized balances of the remaining RSM balances, Columbia and Edgewater precertification and preconstruction deferral balance, and the EPA Notice of Violation deferral at the authorized short-term debt rate.

Accordingly, the Commission finds that the rates of return on average Wisconsin retail electric and natural gas net investment rate bases, which are reasonable for the purpose of determining just and reasonable rates in this proceeding, are as follows:

	Electric	Natural Gas
Weighted Cost of Capital	7.44%	7.44%
Ratio of Average Net Investment Rate Base Plus CWIP to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	93.94%	93.94%
Adjusted Cost of Capital to Derive Percent Return Requirement Applicable to Average Net Investment Rate Base	7.92%	7.92%
Adjustment to Return Requirement to Provide Current Return on CWIP, De Pere Energy Center, Crane Creek, Fox Energy Center, Glenmore, and tax proration at the Adjusted Weighted Cost of Capital	0.47%	0.03%
Adjustment to Return Requirement to Provide Current Return on remaining RSM balances, Columbia and Edgewater precertification and preconstruction balances, and the EPA Notice of Violation at the composite short-term debt rate	0.00%	0.01%
Required Rate of Return on Average Net Investment Rate Base	8.39%	7.95%

Revenue Requirement

On the basis of the findings in this Final Decision, a $24,602,000 increase in Wisconsin retail electric utility revenues and a $15,363,000 decrease in Wisconsin retail natural gas utility revenues are reasonable for the purpose of determining reasonable and just rates in this proceeding and are computed as follows:

	Electric	Natural Gas
Pro Forma Return on Average Net Investment Rate Base at Present Rates	7.44%	10.53%
Required Return on Average Net Investment Rate Base	8.39%	7.95%
Earnings Deficiency (Excess) as a Percent of Average Net Investment Rate Base	0.95%	(2.58%)
Average Net Investment Rate Base (000's)	$1,549,917	$356,382
Amount of Earnings Deficiency (Excess) on Average Net Investment Rate Base (000's)	$14,724	($9,195)
Revenue Deficiency (Excess) to Provide for Earnings Deficiency Plus Federal and State Income Taxes (000's)	$24,602	($15,363)

Electric COSS and Rates

Electric Cost of Service

WPSC, CUB, WIEG, and Commission staff testified regarding cost-of-service study (COSS) issues and the appropriate allocation methods for allocating the plant and operating expenses that make up WPSC's revenue requirement. WPSC prepared three COSS including the applicant's preferred 12CP "Standard" model, as well as two variants of that model. One COSS prepared by the applicant reflected the use of a 4CP demand allocator while the other included a modified distribution system cost allocation reflecting a split between single-phase and three-phase primary distribution costs. WIEG also presented the results of its preferred COSS which combines the cost allocation approach of WPSC's 4CP and single/three-phase studies. Commission staff prepared three additional studies based in part on the methods used by staff in prior WPSC rate case proceedings. While CUB did not submit the results of its own COSS model, CUB testified that, based on its preferred allocation methods, it supported the use of results produced by Commission staff's studies.

While the parties were unable to arrive at consensus regarding the allocation of various plant and operating expenses, the testimony given in this proceeding provided a robust discussion of the merits of the various COSS methodologies employed. The current Commission practice of considering the results of more than one COSS, as well as other factors, when allocating revenue responsibility is supported by this discussion. The Commission finds that it is reasonable to continue to consider the results of more than one COSS along with other factors, such as bill impacts, when allocating revenue responsibility.

As part of the parties' discussion of COSS results, recommendations were made by WPSC, CUB, ELPC, RENEW Wisconsin and Commission staff regarding fixed costs and what class-allocated costs are appropriate to consider for the purposes of setting fixed charge retail rates. Consistent with the way in which the Commission considers COSS results when performing customer class revenue allocation, the Commission finds that it is not reasonable at this time to specify what specific costs are appropriate to consider when setting fixed charge rates for residential and small commercial customers. Identifying specific costs in this proceeding would require the Commission to adopt one COSS, which is contrary to long standing Commission practice.

Electric Revenue Allocation

WPSC proposed an electric revenue allocation that is above average for the residential and the medium commercial class and the industrial class, and below average for the small commercial, lighting, and miscellaneous classes. Commission staff proposed an alternative electric revenue allocation that is below average for the residential classes, the small commercial, lighting and miscellaneous classes, and above average for the medium commercial and the industrial classes. CUB proposed an electric revenue allocation that is below average for the residential, small commercial, lighting, and miscellaneous classes, and above average for the medium commercial and industrial classes.

The overall electric revenue increase in this case includes credits associated with an RSM refund along with other costs that are higher. The credits that were proposed must be applied to the RSM rate classes only. These rate classes include the residential, small commercial, medium commercial, and lighting customers that are all of the rate classes subject to WPSC's RSM.

The Commission generally uses the electric COSS and other information including customer bill impacts as a guide in determining revenue allocation and setting rates. The Commission determines that the reasonable electric revenue allocation is one that reflects a compromise between WPSC's and Commission staff's proposals, with above average increases for the residential and the industrial class and zero increase for the small and medium commercial classes and below average increases for the lighting, and miscellaneous classes, before the application of the RSM credits to the RSM rate classes. The final net changes for 2015 are above average increases for the residential and the industrial class and decreases for the small and medium commercial classes and below average increases for the lighting, and miscellaneous classes. The electric revenue allocation, along with the electric rate design described below and shown in Appendix B for all of WPSC's electric rate classes, is reasonable and appropriately reflects the Commission's consideration of COSS and other factors.

Commissioner Callisto dissents.

Electric Rate Design

WPSC initially proposed an electric rate design, based on its proposed average 8.04 percent electric increase, and subsequently revised its rate design, based on the Commission staff's proposed 2.94 percent electric increase. Both designs included higher demand charges and accompanying lesser increases or decreases in energy charges.

Commission staff proposed changes in customer charges and demand charges, along with increases in energy charges that produce lesser bill impacts for most customers.

CUB proposed maintaining the current customer charges and increases in the energy charges for the residential and small commercial customers to recover the lower revenue allocation that CUB supports for these classes. CUB opposed WPSC's increases for the customer charges.

Customer Charges

WPSC proposed raising the fixed customer charges for a variety of small customer classes for both natural gas and electric customers and decreasing the variable energy rates for these classes by approximately 10 to 13 percent. WPSC's proposed rate realignment would shift the recovery of some of its fixed costs from the variable energy charge to a monthly fixed charge. The customer charges have a direct relationship to the variable energy charges in classes such as these that have no demand charge. Whatever the level of these charges, the entire rate design must recover the test year revenue requirement for each class. For every dollar that is recovered via customer charges, a dollar less needs to be recovered from the energy charge. The converse is also true; if the customer charge is less, energy rates must be higher to recover the same amount of revenue. While the revenue to be recovered from each class is a separate determination, the increases proposed for the fixed charges generated interest from the public and intervenors. A variety of opinions were presented in this proceeding as to what the appropriate fixed charges should be.

In this proceeding, WPSC is asking the Commission to more closely align fixed charges with fixed costs and, to fundamentally, engage in an exercise to enact reforms to restructure the rate design. Such an exercise goes to the core reason why Wisconsin created this Commission: to bring to bear this agency's expertise and knowledge about rates, how they are designed, and the kind of price signals to be sent to customers, and the type of behavior this Commission wants to incent as a matter of sound public policy.[4] In designing rates, the Commission exercises a legislative function in setting policies that reflect the changing nature of the utility industry which includes the emergence of increased customer interest in distributed generation. Each of the parties recognized this basic principle when they asked the Commission to consider various public policy objectives in setting the customer charges. Wisconsin courts have long held that the Commission has wide discretion in determining the factors upon which it may base its rate decisions. Further, the Commission is not bound to any single regulatory formula; it is permitted to make the pragmatic adjustments, which may be called for by particular circumstances, unless its statutory authority plainly precludes this. To the extent that setting rates requires the weighing of evidence, the Commission must use its special experience, technical competence and specialized knowledge to identify a reasonable result, bearing in mind the various public

[4] The dissent draws a narrow and incorrect conclusion about this Commission's expertise. Indeed, this Commission does have the technical and policy expertise to set rates. However, the dissent chooses to focus on the technical knowledge of this agency and its staff, and fails to acknowledge that the Commission also functions in a quasi-legislative manner when setting rates and, thus, the policy and technical expertise of the agency are utilized when setting rates. Under the dissent's interpretation, the Commission would never have to make decisions, but rely only on the advice of Commission staff. This, of course, is incorrect and contrary to this Commission's statutory mandate to weigh the evidence of all parties in rate setting and make decisions based on the entire record.

policies that may be impacted by various rate making decisions. Wis. Stat. §§ 227.57 (6), (8) and (10).

WPSC and WIEG urged the Commission to set the customer charge as close to the fixed costs of the utility such as connecting to the grid, meter costs, billing and other costs that do not vary with usage. In rates designed without demand charges, there are two services conceptually provided by a utility.

First, state law requires that utilities provide reliable and adequate electric service. The utility must build an infrastructure that allows it to provide electricity instantaneously matched to whatever demands a customer places on the system. Theoretically, if a customer requires no electricity for 364 of the 365 days of a year, the utility nevertheless must build an electric system to provide service to this customer for the one day a year this customer requires power. Wis. Stat. § 196.03. There is no dispute that there are certain fixed costs incurred from simply connecting to the system and that the utility is obligated to make its system available regardless of the frequency to which that system will be relied upon by certain customers. WPSC and WIEG urged the Commission to consider customer charges as the portion of the customer bill that pay for, at least in part, this service offered by a utility. For customers with very low usage, this service is sometimes referred to as “backup service.”

The second category of service provided by a utility is the provision of electricity itself. The variable energy charge conceptually represents that cost. Where a particular rate design collects a significant portion of the utility’s fixed costs through the variable energy charge, this results in higher use customers subsidizing lower use customers regardless of the reasons those customers may have lower use. To the extent a customer reduces usage via energy efficiency, conservation or renewable generation, the customer reduces his or her contribution to the utility's fixed costs and these costs must be recovered from other customers. This is the general framework in which the Commission determines what the customer charge and variable energy charges should be within a class.

The Commission agrees with WPSC that the analysis of an appropriate customer charge in this case should begin with attempting to better align the charge with the fixed costs of providing service, regardless of the amount of energy used. At its most basic function, the regulated utility ratemaking process is intended to simulate a free market for monopoly utilities. When rates are properly designed, the rate structure signals to customers the actual cost of providing reliable service and electricity to each class. If the customer charge is too low, the customer will receive an incorrect price signal that the cost to provide access to the electric system is lower than it actually is to the utility. They will also receive an incorrect signal that the variable cost to provide energy is higher than it actually is to the utility. Setting price signals correctly is important because those signals influence customer behavior, which in turn, influences how the utility incurs costs.

As discussed further below, WPSC provides a compelling case that its customer charge is not sufficient to recover its fixed costs. As a result, the variable energy charge is correspondingly too high. The result is a price signal that tells customers that the economic benefit of conservation is higher than it actually is. To the customer, the economic benefit is whatever savings they realize on their bill by implementing efficiency measures or installing renewable energy. But the economic benefit to the system is less than the economic benefit received by individual customers. In other words, if the fixed costs are in part recovered in the variable energy charge, a customer may save $10 per month by conserving electricity, but the utility may only save $6 per month as a result of that customer using less energy. That $4 must then be recovered by other ratepayers the next time rates are adjusted.

Once it is determined to begin with the principle that customer charges should generally align with fixed costs, the question becomes what those fixed costs actually are. Here, the Commission relies upon its longstanding experience and approach to COSSs. COSSs attempt to classify every type of utility cost to provide information about what causes that cost and how it should be allocated. The Commission has traditionally declined to adopt specific COSSs as its preferred approach, and similarly declines here to select one party's proposed definition of "fixed cost" over another. As discussed more specifically below, evidence in the record established that WPSC's fixed costs far exceeded the proposal to raise its customer charge. Thus, it is sufficient in this case that WPSC's proposal moves the customer charge closer to its fixed costs. It is not pragmatic nor necessary at this time to further define fixed costs. The Commission will continue to evaluate this question in the future.

Finally, the intervenors requested the Commission make adjustments to the customer charge for public policy reasons. RENEW Wisconsin and ELPC argued that the Commission should maintain a lower customer charge without regard to the utility's fixed costs in order to support the development of renewable energy and energy efficiency measures. It may be true that raising the customer charge could have an incidental effect upon the payback period of certain energy efficiency measure and renewable energy resources. However, even under WPSC's proposal, 70 percent of a typical customer's bill will remain variable. Thus, many of the intervenors' concerns are overstated.

More importantly, however, the purpose of rate design is not to affect the payback of energy efficiency measures or renewable energy. The purpose of rate design is, fundamentally, to connect the rates customers pay to the costs the utility incurs. Such an approach appropriately encourages efficient utility scale planning.

ELPC and RENEW Wisconsin may believe that privately owned renewable energy resources measures should be supported no matter the effect on other customers, but this fundamental policy decision is firmly left to the Commission. As Wisconsin courts have long recognized, rate design is a quintessential legislative function firmly left to the discretion of the Commission. Other substantial state and federal programs are designed specifically to support the development and implementation of conservation and renewable energy resources. The Commission is not required to use rate design as a hidden subsidy for these resources. This Commission continues to support customers who want to own their own generation; however, the Commission also has an obligation to those customers who do not want to or who cannot afford to own generation to make sure these customers are not subsidizing the costs for those who choose to and are able to own their own generation.

ELPC and RENEW Wisconsin argued that lowering the energy charge will violate the Energy Priorities Law (EPL). They argued that the law would be violated because the proposed rate design would (1) encourage customers to consume more energy (2) render many energy efficiency measures uneconomic, and (3) have a negative impact on Focus on Energy. The Commission is not persuaded that the EPL requires the Commission to disconnect fixed charges from fixed costs. Further, if the Commission accepted ELPC’s argument, then any Commission action that lowered the variable cost of energy would violate the law. In times of falling fuel prices, the Commission regularly requires utilities to give variable credits based on energy use to its customers. Under ELPC's theory, such a credit would be illegal because it lowers the economic benefit of renewable energy by saving customers money on their energy usage. Such a construction of the law would also, if applied to its logical conclusion, prohibit the imposition of any fixed customer charge. This is clearly not a reasonable construction of the statute.[5]

According to the Supreme Court of Wisconsin, the Commission must interpret the EPL in the context its other statutory obligations. *See Clean Wisconsin, Inc. v. Pub. Serv. Comm'n of Wisconsin*, 2005 WI 93, 282 Wis. 2d 250, 700 N.W.2d 768. With respect to the setting of utility rates, the Commission's fundamental obligation is to set just and reasonable rates that ensure the adequate provision of utility service. Wis. Stat. §§ 196.03, 196.20 and 196.37. Nothing in the Energy Priorities Law changes that responsibility. Nor does the energy priorities law require the Commission to favor one group of customers over another.

The text of the law clearly shows that the Commission is not bound to support renewable energy development at the cost of all other ratemaking principles or public policy goals. The law requires the Commission to prioritize the development of renewable energy resources that are "cost effective." Wis. Stat. §§ 1.12 (3)(b) and (4); Wis. Stat. § 196.025(ar). Thus, the law specifically sets forth a state policy that cost effectiveness be a significant consideration in the development of these resources. The law does not require the Commission to artificially inflate, to any degree, the cost effectiveness of renewable energy resources when it sets utility rates.

[5] The dissent argues that the Final Decision "fails to coherently apply our Energy Priorities Law", but fails to explain what, in its view, coherently applying that law might look like. If the law were applied as certain intervenors' suggest, any vote to increase the fixed customer charge would violate it.

The Commission supports energy efficiency and renewable energy in many ways. It supports and regulates the Focus on Energy program which provides direct financial incentives for energy conservation and renewable energy development. The Commission also allows utilities to implement voluntary energy efficiency programs. Finally, the Commission is charged by state law to ensure that the state's utilities comply with the renewable portfolio standard. Rate design is neither the only, nor the most appropriate, tool for policy makers to encourage energy conservation and renewable energy.

Further, the Commission also must consider the effect of adopting ELPC and RENEW's policy choice on customers that cannot implement energy efficiency or renewable measures. To the extent fixed costs are recovered through the variable energy charge, more fixed costs are paid for by higher energy users within a class. The Commission finds that the most equitable result is to better align customer charges with the fixed costs to serve a customer so that, as best as can be determined in a reasonable regulatory environment, members in a class pay for their fair share of the cost of service.

CUB argued that the effect of this rate design change will fall disproportionately upon low income users. WPSC, however, provided substantial evidence that established that low income users are not necessarily low energy or low demand users. Ratepayers will be affected differently based upon how much energy they use, not by their income status. A substantial portion of low income users will realize savings with this rate design compared to CUB's alternative. Furthermore, the total dollar bill impact of these changes is relatively small. While the customer charge for small residential customers will be increased, the variable energy charge will be decreased. As a result, total dollar bill impacts will be small even for the unique customer who uses no energy in a typical month. The Commission finds that CUB's concerns, while worth consideration, are largely overstated and do not warrant deviation from basic rate design principles.

With these policies in mind, the Commission now turns to the specific record evidence offered in this proceeding which support implementation of the Commission's stated policy directives.

While the parties to this proceeding dispute what the fixed charge should be, there is general agreement that there are certain fixed charges incurred from connecting to the grid. (Direct-RENEW-Vickerman-19:11-14; Rabago, Hearing Tr. 193:17-24; Wallach, Hearing Tr. 220:7-18; Singletary, Hearing Tr. 232:20 – 233:1.). The dispute then focused on which specific costs could properly be labelled as fixed, compared to variable.

In WPSC's view, fixed costs include:

> the expenses associated with distribution assets (poles/distribution mains, wires, meters, substations/gate stations, etc.) and administrative costs. Variable costs are the expenses that are directly related to the amount of energy a customer uses. The primary variable costs include fuel and a portion of operating and maintenance expenses.

(Direct-WPSC-Ferguson-2.)

Ms. Ferguson specifically identified the accounts where these categories of costs are assigned and calculated the per customer share of those accounts. Her analysis showed that the total fixed cost to serve the average residential customer is $66.20/month, $34.60 of which is exclusive of generation and transmission. WPSC then proposed raising the residential customer charge to $25.00/month. For the small commercial classes, WPSC proposed raising the customer charge for the single phase customers to $35/month and the three-phase customers to $51/month and provided evidence that justified different fixed costs for single and three-phase customers. [6] WPSC provided evidence that the total fixed cost to serve the average small commercial customer is over $120.

WPSC did not request the customer charge to reflect the actual cost to provide the option of service as they view it, but requested that the customer charge be moved closer to the total fixed costs. Specifically, for residential customers, it requested a customer charge of $25.00/month. Ms. Ferguson also presented testimony that the variable cost of energy is also significantly lower than the energy charge to date, with an approximate value of $.0366/kwh. Thus, WPSC's analysis showed a significant disconnect between the way costs are incurred by the utility (in a fixed fashion, or variable) and how the customers pay for it. Because the revenue requirement is the same within each class, this disconnect means that low energy users pay for less of the fixed costs to connect than they cause the utility to incur. As Ms. Ferguson explained:

> In practice, however, WPSC's fixed and variable charges are out of sync with its fixed and variable costs. This is because, like many utilities, WPSC's tariffs have been structured to recover a significant portion of its fixed costs through variable rates. This means that current fixed charges are set artificially low and current variable charges are set artificially high.

(Direct-WPSC-Ferguson -5.)

Under the analysis presented by WPSC, then, a vacation home that has zero usage in a month, but is connected to the electric system by physical infrastructure and

---

[6] WPSC, like some other Wisconsin utilities, distinguishes between customers who receive service at single phase and three phase in certain cost allocation contexts. In general, receiving service at three-phase is more expensive, requiring more sophisticated meters and bringing three primary wires to the secondary service rather than one.

equipment would pay approximately only $12.00/month for receiving $66.00/month of service. If those customers turned on the lights for 1 hour that month, they have the legal right to adequate and reasonable service. Yet, other customers pay for the costs of connecting this home to the system.

Certain intervenors challenged WPSC's view of which accounts should be theoretically considered "fixed." RENEW Wisconsin offered a very limited view of what should be included as a fixed cost: a meter, the smallest possible wire to serve that customer, the cost to read the meter, and some general overhead. (Direct-RENEW-Vickerman-19.) Mr. Vickerman noted that all other costs identified by the utility as fixed could be more properly understood as "demand" related. Whether or not Mr. Vickerman is correct that the costs identified by WPSC as fixed would be better described as "demand", no Wisconsin utility yet offers demand metering and demand based rates for residential and small commercial customers. As the cost of implementing a demand based type rate structure for residential customers could be prohibitive, the utilities and this Commission must do the best with the available information to determine what portion of the demand component should be recovered through the fixed customer charge based on class averaged data.

Thus, RENEW Wisconsin offers the same solution it criticizes WPSC for: it classifies demand related costs as something else. The Commission does not accept the intervenor's argument that all demand costs are variable, nor is the Commission concluding here that all demand costs must be considered fixed. As Mr. Vickerman recognized in his testimony, all customers contribute to the demand on the system to some degree. As WPSC noted, a customer's contribution to system demand is not necessarily less because they are a low energy customer. Ms. Ferguson provided a specific example and analysis of how DG customers can in fact contribute to demand substantially in excess to their energy. A DG customer may be a net seller of electricity in a year but nevertheless have the same demand on the system as any other customer if they use energy at different times than they produce it for even one day a year. (Rebuttal-WPSC-Ferguson-7-8.) Further, as WPSC noted, projected customer demand then results in the construction of physical assets, that once built, will not cost less if customers use less energy. These assets often have useful lives of 40 years.

In any event, the Commission need not determine which or what proportion of demand related costs should be considered variable or fixed for the purposes of rate design in this case. While WPSC considers demand related costs as fixed, it did not propose to move customer charges to its full cost of service for fixed charges. Further, even under RENEW Wisconsin's limited view of fixed costs, the cost to provide the option for service is greater than the customer charges approved in this Final Decision. Mr. Laursen provided analysis that showed the fixed costs under RENEW Wisconsin's construct would be approximately $6/month *higher* than the customer charge authorized here. (Rebuttal-WPSC-Laursen-3-4.) Thus, while certain parties urge different results for public policy reasons, there is substantial evidence in the record to support the customer charges set by this Final Decision.

The Commission is not persuaded with the arguments that an increase in fixed charges to the levels proposed by WPSC will have a detrimental impact on energy efficiency, conservation or the development of renewables.[7] In this Final Decision, the Commission is approving rates that increase the customer charges by approximately half of what WPSC has proposed. Even under WPSC's proposal, however, the effect on customer's decisions to implement energy efficiency, conservation, or renewable measures is likely to be very small. As Ms. Ferguson noted in her direct testimony:

> Second, although WPSC's proposal would reduce variable rates, the reduction will not necessarily have a material effect on customer decision-making. A reduced variable rate should, in theory, reduce the customer's incentive to conserve and invest in energy efficiency. But practically speaking, if the Commission adopted WPSC's proposed electric rate structure, variable rates would decline by about one cent per kWh ($0.01/kWh) from the current rates. This means that, if a customer reduces her electric consumption by 50 kWh during one month in the summer, she would save fifty cents ($0.50) more under WPSC's current energy rates than she would under the Company's proposed energy rates. Although these are real savings, they are relatively small, and it is important to not overestimate the impact that they have on customer decision-making.
>
> Finally, it is not clear that WPSC's current rate structure is the primary driver behind customer investments in energy efficiency and energy conservation in the first place. Wisconsin's Focus on Energy program requires all investor-owned utilities to spend a certain percentage of their operating revenues on energy efficiency and renewable resource programs. These funds are used to support programs that offer financial incentives and technical support to ratepayers for energy efficient products and services. It is likely that these incentives are just as or even more important than WPSC's variable rates in terms of motivating customers to invest in energy efficiency and energy conservation.

(Direct-WPSC-Ferguson-10 -11.)

Further, whether or not the shifting of costs between customer charges and energy charges is material in the context of renewable energy payback, the Commission must consider the impact of rate design on all customers. The Commission is concerned that the failure of low usage customers to pay for their fixed costs will cause costs to go up for other customers.

[7] The dissent is critical of the Commission's determination and impermissibly resorts to non-record evidence in an attempt to demonstrate that increasing fixed charges may impact energy efficiency. (Dissent, at 9, fn. 23.)

Ms. Ferguson explained how the inclusion of fixed costs in energy charges subsidizes customers who can afford to implement renewable energy measures at the cost of those who cannot:

> Although the fixed and variable charges are not aligned, the average residential customer uses enough energy to cover his or her fixed costs. This isn't the case with customers that own distributed generation. DG-customers can supply their own electricity, which displaces electricity that they would otherwise purchase from WPSC. This produces savings for the DG-customer, but a significant portion of those savings stem from the customer's ability to avoid paying the fixed costs that WPSC recovers through its variable rates. WPSC incurs fixed costs in serving DG-6 customers, just as it incurs fixed costs in serving any other customer that it is obligated to serve. WPSC maintains the distribution infrastructure that serves DG customers when they do not produce enough energy to meet their own needs, or when they need to sell excess electricity back to the grid. DG-customers currently rely on the grid for these critical services without having to fully compensate WPSC for the fixed costs that it incurs in providing them. This inevitably shifts costs to other non-DG customers, who must shoulder a larger portion of WPSC's fixed costs in their variable rates.
>
> For example, in 2013, on an annual basis, approximately 35% of the 340 Pg-4 (net 16 metering) customers did not consume and pay for an amount of energy sufficient to cover their fixed distribution costs. Some of these customers actually over-generated and pushed electricity back to WPSC's distribution system. These customers are not only failing to compensate WPSC for the full fixed costs of receiving electricity, but are also not paying for the infrastructure that allows them to sell energy to WPSC. WPSC must make up for this shortfall by ultimately shifting more of the burden for fixed costs to non-DG customers.
>
> There is an additional layer to the cross-subsidization that occurs between DG and non-DG customers. There are substantial up-front costs associated with installing distributed generation resources, such as solar panels. Accordingly, customers who can afford to install DG will do so and reduce their own costs, while those who cannot afford to install DG will shoulder an increasingly larger portion of WPSC's fixed costs through variable rate increases. Accordingly, if WPSC's current rate structure remains unchanged, more affluent customers will reduce their costs by installing DG, and lower income customers will be forced to bear a disproportionate share of the grid's fixed costs. This is an inequitable result, and adopting WPSC's proposed rate structure will ensure that those who cannot afford to install DG remain protected.

(Direct-WPSC-Ferguson-12-13.)

The opponents of WPSC's proposal finally noted that the current cost of the subsidy created by a disconnect between a utility's fixed cost and its customer charge is small compared to the total revenues of the utility. They ask the Commission to ignore that subsidy as immaterial compared to their favored policy objectives. Commission staff witness Mr. Singletary favored a lesser increase to the customer charges arguing that in his opinion, the current subsidy of DG customers is small. But he nevertheless recognized that the implementation of distributed generation "likely present(s) cost recovery challenges in the future for Wisconsin utilities."

In any event, the Commission agrees with WPSC that over time, this disconnect may grow exponentially. Each year, renewable energy resources become cheaper and more attractive to utility ratepayers who can afford them. The use of distributed generation is expected to continue to grow, requiring more and more fixed costs to be paid for by non-participating customers. Further, the intra-class subsidy is not just limited to renewable energy owners. Every low energy use customer is paying less than their proportionate share of the fixed cost to provide access to the electric system. Thus, the magnitude of the subsidy is much greater than argued by RENEW Wisconsin. The Commission prefers to more correctly align costs now when the relative impacts are small rather than waiting until the effect of such an adjustment could be shocking to the ratepayers.

Further, while all parties urged different results for policy reasons, there is no debate that utilities incur basic costs to provide backup service or access to the grid. Ultimately, the Commission must weigh the opinions of the parties, the testimony presented, and balance the various goals of rate design and public policy.

In order to reduce intra-class subsidies, to provide more appropriate price signals to ratepayers and encourage efficient utility scale planning, the Commission determines that the fixed customer charges should be increased to more closely reflect the utility's fixed costs to provide basic service to a customer. However, at this time, the Commission declines to increase the fixed charges as substantially as requested by WPSC. Ultimately, the Commission favors the policies set forth by WPSC, but recognizes the concerns raised by some of the intervenors and further desires to transition to higher customer charges in a more gradual manner than proposed by the utility. Any further increase to customer charges will be considered in a subsequent rate proceeding, which will allow each of the parties to again present evidence and argument as to the appropriate customer charge for that year. The Commission determines that it is a reasonable balance, after weighing the testimony and policy arguments presented by the parties, to set the customer charge to $19/month for residential classes, $25/month for the single phase small commercial class and $40/month for the three phase small commercial classes.

Commissioner Callisto dissents.

Medium Commercial (Cg-20) and Large Commercial and Industrial-General (Cp) Rates

WPSC's proposals for the Cg-20 customers included an increase in the customer charge and large increases for the demand charges along with lesser increases or decreases for the energy charges. WPSC also proposed large increases for the Cp demand charges along with lesser increases or decreases for the Cp energy charges.

Walmart proposed that all of the increase allocated to the medium commercial, Cg-20, rate class be recovered via higher demand and customer charges with no change to the energy charges. WIEG generally supported WPSC's proposed changes in the demand and energy charges for the Cp rate class.

The Commission determines that WPSC's electric rate design, as adjusted for the final revenue requirement and the revenue allocation summarized above, is reasonable. This includes large increases in the levels of the customer charges and large increases in the demand charges along with small increases or decreases for the energy charges. The changes for the Cg-20 class more closely align rates for this class with the cost of service. Similarly, the changes for the Cp class also more closely match the cost of service and give industrial customers an incentive to reduce demand, which benefits all customers. All of the electric rates are shown in Appendix B.

Commissioner Callisto dissents.

Interruptible Credits

WIEG proposed to increase the credits for interruptible service. WIEG argued that the interruptible credits had not been increased for some time even though firm demand charges had been increased and that this had resulted in an increase in the differential between the firm demand charge and the interruptible demand charge. WPSC's rate design maintained the credits at their current amounts and opposed increasing the interruptible credits. WPSC argued that interruptible customers need only make a short-term commitment to take interruptible service and that the current value of short-term capacity was very low. Commission staff's proposed rate design also maintained the interruptible credits at the current amounts.

The Commission finds that it is reasonable to maintain the interruptible credits at the current amounts. The existing credits provide an adequate incentive for industrial customers to designate load as interruptible and strikes a reasonable balance between low capacity prices in MISO and the cost of new entry.

Electric Tariff Language Changes

WPSC's proposed changes to its electric extension allowances, miscellaneous clean-up language changes to its electric service rules, the cancellation of the Ms-31 street lighting tariff and modifications to its Ls-1 lighting tariff. There were no objections to these changes. The Commission finds that it is reasonable to approve these tariff changes as shown in Ex.-WPSC-Beyer-1.

Real Time Market Pricing (RTMP) Rate

Order Point 18 of the Commission's Final Decision in docket 6690-UR-122 directed the utility to work with WIEG and other appropriate stakeholders to evaluate the energy adder in the RTMP rate schedule. WPSC provided testimony and analysis of RTMP related costs that are meant to be covered by the RTMP rider. WPSC proposed to maintain the RTMP adder rate at the current rate of $10 per-MWh, which was set in WPSC's last rate case. WIEG objected to the $10 RTMP rider, along with certain costs WPSC identified as part of its analysis of the RTMP rate. In particular WIEG objected to the "option value" included in WPSC's cost analysis. WIEG proposed to reduce the RTMP adder to $5 per-MWh or $6 per-MWh. WPSC indicated that it might be open to lowering the RTMP rider to $6 per-MWh, if the rate change was accompanied by an increase in the length of the customer's contractual commitment to the RTMP service.

In addition to its objections over the RTMP rider itself, WIEG expressed dissatisfaction with the lack of communication and engagement on the part of WPSC relating to WPSC's compliance with Order Point 18. WIEG testified that WPSC did not meet with them prior to the filing of the utility's rate case and rate design, despite Order Point 18 directing WPSC to do so.

In light of cost analysis provided by WPSC in this proceeding, which suggests a range of $6.43 per-MWh to $16.43 per-MWh, the Commission finds it reasonable at this time to maintain the RTMP rider at its current level of $10 per-MWh. However, the Commission is deeply troubled by WPSC's failure to comply with the Commission's order in docket 6690-UR-122. The Commission finds it necessary to again direct WPSC to meet with WIEG and other interested stakeholders to evaluate the RTMP adder. WPSC shall report back to the Commission no later than April 2, 2015, on the status of these discussions.

Customer Owned Generation Rates

Order Point 19 of the Commission's Final Decision in docket 6690-UR-122 directed WPSC to conduct an in depth review of market-based buyback rates in the utility's next base rate case (this proceeding) to determine whether the rates are functioning appropriately. WPSC's witness testified regarding the applicants review of its Pg-2A and Pg-2B parallel generation tariffs, whose rates are set based on MISO locational marginal prices (LMP). In addition to an energy credit rate, the presently authorized Pg-2A and Pg-2B tariffs include a capacity credit based on the clearing price of the annual MISO capacity auction. This price is posted in April for the June to May MISO planning year that immediately follows. Currently the capacity credit is updated on January 1 of each year based on the capacity price set in April of the prior year. Commission staff recommended that the update cycle for the Pg-2A and Pg-2B capacity credit be shifted so as to update the capacity credit rate effective June 1 of each year so as to more closely track the timing of the MISO capacity auction. Under Commission staff's proposal the energy credit rates for Pg-2A would continue to be updated January 1 of each year. WPSC did not provide testimony regarding Commission staff's proposal. The Commission finds staff's proposal to modify the update cycle for the Pg-2A and Pg-2B capacity credit to be reasonable. This change will reduce the delay between the market capacity price being set by MISO and the customer receiving that credit for energy sold to the company.

Commission staff also provided testimony proposing that an avoided transmission cost credit be implemented for Pg-2A and Pg-2B customers. The presently authorized Pg-2A and Pg-2B tariffs do not include a credit of avoided transmission costs. WPSC objected to Commission staff's proposal, indicating that it did not believe that customer owned distributed generation is capable of reducing the utility's transmission cost.

While the Commission recently authorized distributed generation buyback rates that include a credit for the utility's avoided transmission cost in Wisconsin Electric Power Company's recent rate case, docket 5-UR-106, the Commission does not find there to be sufficient evidence in the record of this proceeding to implement such a credit for WPSC. It has not been established in this record that the installation of DG, at this time, will allow the utility to avoid any measurable transmission costs. WPSC shall meet with RENEW Wisconsin, Commission staff, and other interested stakeholders to discuss a proposal for possible inclusion of an avoided transmission cost credit for Pg-2A and Pg-2B customers in future rate case proceedings.

Commissioner Callisto dissents.

Commission staff provided testimony suggesting that WPSC be directed to perform a detailed study of the DG within its service territory, with the results provided as part of the utilities next base rate case filing. Commission staff suggested that such a study may help to better inform the Commission regarding DG rate design for WPSC in future proceedings. ELPC and RENEW Wisconsin similarly recommended that the utility either be directed to perform a DG study or be directed to contract with a third party to conduct such a study.

While the Commission recognizes the parties' interest in further study of DG related issues, the Commission finds that there is sufficient evidence in the record upon which to base its decisions in this proceeding, as they relate to DG. Additionally, as is evidenced by the volume of testimony in this proceeding, the Commission continues to believe that individual utility rate proceedings provide for a sufficient and robust examination of DG issues. As such the Commission does not find it necessary to direct WPSC to perform a DG study, direct WPSC to contract with a third party to conduct such a study, or to open a separate Commission investigation into DG issues and rate design.

Commissioner Callisto dissents.

Natural Gas COSS, Rates, and Rules

Natural Gas COSS

WPSC prepared a customer-oriented COSS and Commission staff prepared two COSS to establish a range of reasonableness: a customer-oriented COSS (COSS A) and a commodity-oriented study (COSS B). WPSC's and Commission staff's COSS A allocates costs based on number of customers, average usage and peak demand. Commission staff's COSS B allocates main-related costs on commodity and customer demands, not on number of customers. Customer-oriented studies generally result in higher costs to low-volume service rate classes and lower costs to large-volume service rate classes, when compared to the results of commodity-oriented COSS.

WIEG was critical of all three studies because they allocate transmission-related capacity costs based on coincidental monthly peak demands and recommended a coincidental daily peak demand allocation. In future rate case proceedings, WPSC shall examine an allocation on the daily peak demand of its service rate classes, but this examination should not be to the exclusion of the other COSS that provide a range of results for the Commission to consider.

The Commission has not endorsed a particular natural gas COSS methodology in the past and has relied on the results of all of the COSS to provide a range of reasonableness for revenue allocation and rate design. This continues to be an appropriate policy.

Revenue Recovery Adequacy of Service Class Rates

Overall, the rates authorized for WPSC in Appendix C of this Final Decision will provide a 7.95 percent rate of return on the average gas net investment rate base. This represents a decrease of 11.85 percent in margin rates and 4.28 percent increase in total natural gas sales revenues. Margin rates exclude natural gas costs from the increase calculations.

Authorized rates as set forth in Appendix C are based on the cost of supplying natural gas service to the various service rate classes and other rate setting goals. A summary of the revenue rate impacts on a service rate class is shown in Appendix C.

As shown in Appendix C, the natural gas COSS results in a relatively wide range of changes in the charges to the various service rate classes. To provide for historical continuity in WPSC's rates, the Commission finds it reasonable to authorize service rates that move in the direction of the natural gas COSS results, with the intent to make further adjustments in that direction in subsequent rate proceedings. In moving toward the cost of service in authorized rates, the Commission tempers the rate increase to the service rate classes that, according to the cost analysis, should receive the largest percentage increases. The resulting revenue difference is recovered through the rates of the remaining service rate classes. The percentage rate change to any individual customer will not necessarily equal the overall percentage change to the associated service rate class, but will depend on the specific usage level of the customer.

Appendix C shows some typical natural gas bills for residential service, comparing existing rates with new rates including the cost of natural gas.

Fixed General Service Monthly Charges for Residential Customers and the Smallest Volume Commercial Service Rate Class

WPSC proposed to raise the monthly customer service charge for residential/small standard volume commercial, medium volume commercial, and large volume commercial natural gas customers from $10.25 to $18.00, $135 to $170, and $595 to $750, respectively, to better align charges with the type of cost, provide better price signals, provide more equity between higher-use and lower-use customers within the same rate class, and provide more bill stability between seasons. WPSC revised the proposed charges to $17.00, $150, and $620 based on WPSC's gas COSS updated for Commission staff's audited adjusted revenue excess.

Although authorized overall residential and small commercial rate revenues will result in a decrease, the rates will result in an increase or smaller decrease to small-volume users than for larger-volume users within the same service class. This is the result of the higher authorized percentage increases in the fixed daily distribution service charge over the volumetric distribution service charges. For example, the overall 14.72 percent decrease in the WPSC residential margin revenues consists of a 65.85 percent increase in the fixed daily distribution service revenues and a 61.16 percent decrease in volumetric distribution service revenues. Small-volume customers will experience the highest percentage increase in rates because their bills are comprised of proportionately more of the fixed daily distribution service charge than the volume charges when compared to larger volume users. At a minimum, the authorized fixed charges for residential customers and the smallest volume commercial customers are designed to recover customer costs including meter reading, billing, and collecting expenses, and the depreciation and return associated with meters and service laterals. The authorized fixed service charges are also designed to recover a portion of the applicant's fixed costs. The applicants incur these costs regardless of the volume of gas used by their customers, so it is more appropriate to recover such costs through fixed service charges than through volumetric charges.

The Commission finds that WPSC's proposal is reasonable. As discussed above and for the same policy reasons previously articulated relating to electric fixed costs, the Commission prefers that fixed service charges generally reflect fixed costs to avoid intra-class subsidies and to provide appropriate price signals to ratepayers. Some typical gas bills for residential customers were computed to compare existing rates with authorized rates. The comparisons are set forth in Appendix C.

Commissioner Callisto dissents.

Short-Term CDGT Service

The purpose of WPSC's CDGT tariff was to provide for a short-term discounted rate for natural gas service given the competitive price of coal utilization facilities. The tariff included conditional provisions. One such provision stated: "The customer must be unable to obtain natural gas under any other schedule of the Company at a price competitive with the customer's existing coal utilization facilities." WPSC's largest volume users subscribe to service under its Cg-SL tariffs. The increase to any CDGT customer represents an elimination of the discount and an adoption of rates for service to WPSC's largest volume users. Cg-SL rates are competitive with existing coal utilization facilities so it is reasonable to eliminate WPSC's CDGT tariff. The Commission concludes that it is appropriate to eliminate WPSC's CDGT tariff. Gas prices are much more competitive with coal today than they were in 1987. As a result, it is no longer reasonable to provide discounted pricing for the purposes of providing industrial customers the incentive to switch from coal to natural gas as a fuel. Elimination of the CDGT tariff completes a transition that was begun in previous rate proceedings for WPSC.

Chairperson Montgomery dissents and would have retained the tariff for the reasons articulated by WIEG.

Gas Extension Rules

Natural gas extension rules are set in each gas utility's tariff filings in Wisconsin. WPSC charges a 32 percent tax gross-up charge to large extension projects, which is designed to make up for the dollar difference between the year one income tax payment made by a utility and the total tax advantage, received over time, from the depreciation of the gas main extension project. WPSC is the only utility in the state that applies a gross-up. While tax gross-ups were once approved more broadly by the Commission, the Commission has been requiring utilities to remove them from extension rules in recent years. This was done most recently in docket 5-UR-103 for Wisconsin Electric Power Company. Kwik Trip requested that WPSC eliminate this charge. The Commission finds that it is reasonable to eliminate this charge to bring the company's gas extension rules in line with the other gas utilities in the state.

Aggregation of allowances

Natural gas extension allowances are intended to defray the cost to a customer of a gas main or service line extension. Allowances reflect the recognition that, by promoting the realization of scale economies, gas extension projects can promote reductions in the unit cost of gas delivery services that benefit all utility customers.

WPSC does not aggregate allowances, but rather applies allowance calculations to a single gas main extension project that is contiguous and time frame specific. No other Wisconsin investor-owned utility allows for the aggregation of allowances between multiple gas main extension projects.

Kwik Trip proposed that if a customer has requested multiple extensions, the customer should be allowed to aggregate the allowances. Aggregating the allowances decreases the portion of gas main extension costs currently paid by the new customer and would result in more costs being borne by existing WPSC customers. The Commission finds that the current practice of not aggregating gas customer extension allowances is reasonable, consistent with the language in the tariff, and shall continue, in order to protect current ratepayers from undue cost increases. Requiring aggregation of allowances would not only result in more gas extension costs being socialized than was originally intended, but would unnecessarily add to the administrative difficulty of tracking costs and allowances when a customer has multiple active extension projects.

First User

Kwik Trip argued that WPSC's gas extension costs are higher than other Wisconsin gas utilities, despite the fact that WPSC's gas extension tariffs are similarly structured to those utilities. Kwik Trip alleged that WPSC assigns more cost to the "first user" than to general system improvements and subsequent customers. The Commission notes that gas extension projects are unique and fact-specific. Projects that appear to be similar often differ significantly in cost due to the requirements of the customer, the characteristics of the existing gas distribution system, construction methods and materials, and other factors. As a result, it is difficult to determine whether these costs are generally being appropriately assigned without evaluating the specific facts for each project. It is not clear from the record in this case whether differences in gas extension cost are based on differences in tariff interpretations or on differences in location and facilities involved in construction.

Nonetheless, the Commission directs Commission staff to investigate, through the issuance of data requests to all natural gas utilities in Wisconsin, how other gas utilities interpret and apply their tariffs to "first users." The Commission further directs WPSC, Kwik Trip, Commission staff, and any other interested parties to continue to discuss these extension rules and how to appropriately value "first user" benefits versus system-wide benefits.

Effective Date

The Commission finds it reasonable for the authorized electric and natural gas rate increases and all tariff provisions that restrict the terms of service to take effect no sooner than January 1, 2015, provided that these rates and tariff provisions are filed with the Commission and makes them available to the public pursuant to Wis. Stat. § 196.19 and Wis. Admin. Code § PSC 113.0406(1)(a) and 134.13(1)(b). If these rate increases and tariff provisions are not filed with the Commission and made available to the public by that date, it is reasonable to require that they take effect one day after the date they are filed with the Commission and made available to the public.

The Commission finds it reasonable for the authorized electric and natural gas rate decreases and all tariff provisions that do not restrict the terms of service to take effect January 1, 2015. It is also reasonable to require that the utility file these rate decreases and tariff provisions with the Commission and make them to the public pursuant to Wis. Stat. § 196.19 and Wis. Admin. Code § PSC 113.0406(1)(a) and 134.13(1)(b) by that date.

Order

1. This Final Decision takes effect one day after the date of service.

2. The authorized rate increases and tariff provisions that restrict the terms of service may take effect no sooner than January 1, 2015, provided that the utility files these rates and tariff provisions with the Commission and makes them available to the public pursuant to Wis. Stat. § 196.19 and Wis. Admin. Code § PSC 113.0406(1)(a) and 134.13(1)(b) by that date. If these rate increases and tariff provisions are not filed with the Commission and made available to the public by that date, they take effect one day after the date they are filed with the Commission and made available to the public.

3. WPSC may revise its existing rates and tariff provisions for electric and natural gas utility service, substituting the rate increases and tariff provisions that restrict the terms of service, as shown in Appendices B and C or as described in this Final Decision. These changes shall be in effect until the Commission issues an order establishing new rates and tariff provisions.

4. The authorized rate decreases and tariff provisions that expand the terms of service shall take effect January 1, 2015. WPSC shall file these rate decreases and tariff provisions with the Commission and make them available to the public pursuant to Wis. Stat. § 196.19 and Wis. Admin. Code § PSC 113.0406(1)(a) and 134.13(1)(b) by that date.

5. By January 1, 2015, WPSC shall revise its existing rates and tariff provisions for electric and natural gas utility service, substituting the rate decreases and tariff provisions that expand the terms of service, as shown in Appendices B and C or as described in this Final Decision. These changes shall be in effect until the Commission issues an order establishing new rates and tariff provisions.

6. WPSC shall prepare bill messages that properly identify the rates authorized in this Final Decision. WPSC shall provide the messages to customers no later than the first billing containing the rates authorized in this Final Decision, and shall file copies of these bill messages with the Commission before it provides the messages to customers.

7. WPSC shall file tariffs consistent with this Final Decision.

8. In future rate case filings, WPSC shall specifically identify how it reflects estimated savings due to the ICE project.

9. WPSC shall meet with WIEG, Commission staff and other interested stakeholders to evaluate the RTMP adder and report back to the Commission no later than April 2, 2015, on the status of the discussions.

10. WPSC shall annually update the Pg-2A and Pg-2B capacity credit rate so as to be effective June 1, coinciding with the June to May MISO planning year, based on the most recent results of the MISO capacity auction.

11. WPSC shall meet with RENEW Wisconsin, Commission staff, and other interested stakeholders to discuss a proposal for possible inclusion of an avoided transmission cost credit for Pg-2A and Pg-2B customers in future rate case proceedings.

12. The electric fuel costs in Appendix D shall be used for monitoring WPSC's 2015 fuel costs pursuant to Wis. Admin. Code § PSC 116.06(3).

13. All 2015 fuel costs shall be monitored using a plus or minus 2 percent tolerance band.

14. WPSC shall defer any minimum tonnage obligation costs incurred during 2015 for possible future rate recovery. WPSC shall submit a detailed analysis documenting its efforts to eliminate or minimize these costs when it seeks rate recovery for these costs.

15. WPSC shall defer the actual undepreciated balance of retired plant associated with Pulliam units 5 and 6 and Weston unit 1 and amortize at an amount of $133,000 per month, starting with the actual retirement date, and concluding when the balance is fully amortized.

16. WPSC shall submit a ten-year financial forecast in its next rate case.

17. WPSC shall not pay, without Commission prior approval, normal dividends greater than 103 percent of the prior year's common dividend. WPSC shall notify the Commission if any special dividend is contemplated. No special dividend that might cause the common equity, on a financial basis, to drop below the projected calendar year average of 51.00 percent or the dollar amount of equity reflected in the test year is permitted without Commission approval.

18. WPSC shall submit, in its next rate case application, detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt

equivalent. The information shall include, at minimum: (1) the minimum annual lease and PPA obligations; (2) the method of calculation along with the calculated amount of the debt equivalent; and (3) supporting documentation, including all reports, correspondence and any other justification that clearly established S&P's and other major credit rating agencies' determination of the off-balance sheet debt equivalent, to the extent available, and publicly available documentation when S&P and other major credit rating agencies documentation is not available.

19. WPSC shall record annual conservation accrual amounts of $16,531,716 for electric utility operations and $3,088,112 for natural gas utility operations. The level for electric utility operations consists of the conservation budget of $15,905,942 and an escrow amortization adjustment of $625,774. The electric escrow adjustment represents the test-year amortization of the projected overspent escrow balance at December 31, 2014, over two years. The level for natural gas operations consists of the conservation budget of $4,732,317 and an escrow amortization adjustment of ($1,644,205). The natural gas escrow adjustment represents the test-year amortization of the projected underspent escrow balance at December 31, 2014, over two years. WPSC shall continue to record these amounts until the Commission authorizes new conservation accrual amounts.

20. WPSC shall work with Commission staff to develop metrics of success for the 2015 customer service conservation activities approved by the Commission. WPSC shall submit its customer service conservation measures of success to the Commission by January 31, 2015.

21. If WPSC does not apply for a rate case for a 2016 test year, WPSC shall work with Commission staff to develop metrics for its 2016 customer service conservation activities by no later than October 1, 2015.

22. WPSC is authorized electric and natural gas RSM rates that sunset December 31, 2015 for the one-year amortization of the over recovery of revenue generated from 2013 sales.

23. In future rate case proceedings, WPSC shall prepare a natural gas COSS that allocates natural gas transmission-related capacity costs on each class's coincident peak day demand factors.

24. WPSC is authorized to substitute for its existing rates and rules for natural gas service, the rate and rule changes contained in Appendix C. These changes shall be in effect until the issuance of an order by the Commission establishing new rates and rules.

25. The gross-up of customer contributions for gas extensions shall be eliminated.

26. The practice of not aggregating extension allowances for new gas customers shall continue.

27. Commission staff shall investigate, through the issuance of data requests to all gas utilities in Wisconsin, how other gas utilities interpret and apply their tariffs to "first users."

28. Jurisdiction is retained.

Concurrence and Dissent

Commissioner Callisto concurs, in part, and dissents, in part, and writes separately (see attached).

Concurrence

Commission Nowak concurs and writes separately (see attached).

Dated at Madison, Wisconsin, this 18th day of December, 2014.

for

Sandra J. Paske
Secretary to the Commission

SJP:CWL:cmk:DL:00948296

See attached Notice of Rights

PUBLIC SERVICE COMMISSION OF WISCONSIN
610 North Whitney Way
P.O. Box 7854
Madison, Wisconsin 53707-7854

NOTICE OF RIGHTS FOR REHEARING OR JUDICIAL REVIEW, THE TIMES ALLOWED FOR EACH, AND THE IDENTIFICATION OF THE PARTY TO BE NAMED AS RESPONDENT

The following notice is served on you as part of the Commission's written decision. 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.

PETITION FOR REHEARING

If this decision is an order following a contested case proceeding as defined in Wis. Stat. § 227.01(3), a person aggrieved by the decision has a right to petition the Commission for rehearing within 20 days of the date of service of this decision, as provided in Wis. Stat. § 227.49. The date of service is shown on the first page. If there is no date on the first page, the date of service is shown immediately above the signature line. The petition for rehearing must be filed with the Public Service Commission of Wisconsin and served on the parties. An appeal of this decision may also be taken directly to circuit court through the filing of a petition for judicial review. It is not necessary to first petition for rehearing.

PETITION FOR JUDICIAL REVIEW

A person aggrieved by this decision has a right to petition for judicial review as provided in Wis. Stat. § 227.53. In a contested case, the petition must be filed in circuit court and served upon the Public Service Commission of Wisconsin within 30 days of the date of service of this decision if there has been no petition for rehearing. If a timely petition for rehearing has been filed, the petition for judicial review must be filed within 30 days of the date of service of the order finally disposing of the petition for rehearing, or within 30 days after the final disposition of the petition for rehearing by operation of law pursuant to Wis. Stat. § 227.49(5), whichever is sooner. If an *untimely* petition for rehearing is filed, the 30-day period to petition for judicial review commences the date the Commission serves its original decision.[8] The Public Service Commission of Wisconsin must be named as respondent in the petition for judicial review.

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

Revised: March 27, 2013

---

[8] *See State v. Currier*, 2006 WI App 12, 288 Wis. 2d 693, 709 N.W.2d 520.

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates

6690-UR-123

SERVICE LIST

CITIZENS UTILITY BOARD
Kira E. Loehr
James Woywod
16 North Carroll Street, Suite 640
Madison, WI 53703 Ph.
608-251-3322
loehr@wiscub.org
woywod@wiscub.org

COMMISSION STAFF (Not a Party)
Justin Chasco
Christopher Larson
Public Service Commission of Wisconsin
610 North Whitney Way
PO Box 7854
Madison, WI 53707-7854
Justin.chasco@wisconsin.gov
Christopher.Larson@wisconsin.gov

CONSTELLATION NEW ENERGY-GAS DIVISION LLC
Darcy Fabrizius
Manager, State Government and Regulatory Affairs
Constellation NewEnergy-Gas Division, LLC
N21 W23340 Ridgeview Parkway
Waukesha, WI 53188
PH. 262-506-6600
Darcy.fabrizius@constellation.com

ENVIRONMENTAL LAW & POLICY CENTER
Bradley D. Klein
Howard A. Learner
Stephanie K. Chase
222 S. Hamilton Street, Suite 14
Madison, Wisconsin 53703 Ph.
(608) 204-9735
bklein@elpc.org
hlearner@elpc.org
schase@elpc.org

IUOE LOCAL 420
Paul Zakszewski
2924 W. Hilltop Lane
Franklin, WI 53132
zakpk7679@sbcglobal.net

KWIK TRIP INC.
Peter L. Gardon
Bryan K. Nowicki
Reinhart Boerner Van Deuren S.C.
22 East Mifflin Street, Suite 600
Madison, WI 53703
Ph. 608-229-2200
pgardon@reinhartlaw.com
bnowicki@reinhartlaw.com

RENEW Wisconsin
David C. Bender
James N. Saul
McGillivray Westerberg & Bender LLC
211 South Paterson Street, Suite 320
Madison, WI 53703
Ph. 608-310-3560
bender@mwbattorneys.com
saul@mwbattorneys.com
mvickerman@renewwisconsin.org

WAL-MART STORES EAST LP
SAM'S EAST INC.
Rick D. Chamberlain
Behrens, Wheeler & Chamberlain
6 N.E. 63rd Street, Suite 400
Oklahoma City, OK 73105
Ph. 405-848-1014
rchamberlain@okenergylaw.com

WISCONSIN INDUSTRIAL ENERGY GROUP, INC.
Steven A. Heinzen
Heinzen Law, S.C.
Two East Mifflin Street, Suite 402
Madison, WI 53703
Ph. 608-209-7468
Steve.heinzen@heinzenlaw.com
tstuart@wieg.org

WISCONSIN PAPER COUNCIL
Earl Gustafson
5485 Grande Market Drive, Suite B
Appleton, WI 54913
Ph. 920-574-3752
gustafson@wipapercouncil.org

WISCONSIN PUBLIC SERVICE CORPORATION
Bradley D. Jackson
Foley & Lardner, LLP
150 East Gilman Street
Madison, WI 53703
Ph. 608-258-4262
bjackson@foley.com
DJKyto@integrysgroup.com
PJCampshure@integrysgroup.com

Wisconsin Public Service Corporation

SUMMARY OF ELECTRIC REVENUE BY RATE CLASS

Rate Schedule	Rate Class Descriptions	Present Revenue	Authorized Revenue	Revenue Change	Percentage Change
Rg-1	Residential	$341,904,663	$351,988,155	$10,083,493	2.9%
Rg3-OTOU	Residential - Optional TOU	$16,178,359	$16,643,749	$465,390	2.9%
Rg5-OTOU	Residential - Optional 3-part TOU	$3,490,725	$3,593,153	$102,429	2.9%
Cg-1	Small C&I - Less than 50 kW	$110,507,531	$110,024,665	($482,866)	-0.4%
Cg3-OTOU	Small C&I - Optional TOU	$9,997,182	$9,947,018	($50,163)	-0.5%
Cg-5	Small C&I - 50 to 100 kW	$36,260,976	$36,070,522	($190,454)	-0.5%
Cg-20	Cg TOU - 100 to 1000 kW	$205,951,726	$212,010,626	$6,058,900	2.9%
Cp	Industrial - Greater than 1000 kW	$239,211,404	$247,696,002	$8,484,598	3.5%
ATS-1	Automatic Transfer Switch	$54,372	$54,891	$519	1.0%
Pg	Parallel Generation	$13,758	$11,322	($2,436)	-17.7%
NAT	Naturewise	$264,754	$264,754	$0	0.0%
Ls-1/Ms-31	Street Lighting	$13,278,449	$13,408,545	$130,096	1.0%
Totals		**$977,113,897**	**$1,001,713,402**	**$24,599,505**	**2.5%**

Wisconsin Public Service Corporation
SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedule / Rate Class & Description of Rate Components	Present Rates	Authorized Rates
Rg-1 Residential Service		
Monthly Fixed Charge	$10.40	$19.00
Daily Fixed Charge	$0.3419	$0.6247
Monthly Fixed Charge (Seasonal)	$20.80	$38.00
Daily Fixed Charge (Seasonal)	$0.6838	$1.2493
Energy Charge (per kWh)	$0.11345	$0.10267
Rg3-OTOU Residential Service - Optional Time-of-Use (Closed to New Customers)		
Monthly Fixed Charge	$10.40	$19.00
Daily Fixed Charge	$0.3419	$0.6247
Monthly Fixed Charge (Seasonal)	$20.80	$38.00
Daily Fixed Charge (Seasonal)	$0.6838	$1.2493
Energy Charge (per kWh)		
On-Peak	$0.20200	$0.19090
Off-Peak	$0.06507	$0.06112
Controlled Water Heating		
Monthly Control Charge	$4.80	$4.80
Daily Control Charge	$0.1578	$0.1578
Monthly Control Charge (Seasonal)	$9.60	$9.60
Daily Control Charge (Seasonal)	$0.3156	$0.3156

Wisconsin Public Service Corporation
SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedule / Rate Class & Description of Rate Components	Present Rates	Authorized Rates
Rg5-OTOU Residential Service - Three-Tier Optional Time-of-Use		
Monthly Fixed Charge	$10.40	$19.00
Daily Fixed Charge	$0.3419	$0.6247
Monthly Fixed Charge (Seasonal)	$20.80	$38.00
Daily Fixed Charge (Seasonal)	$0.6838	$1.2493
Energy Charge (per kWh)		
On-Peak	$0.25616	$0.23321
Shoulder	$0.11345	$0.10267
Off-Peak	$0.06507	$0.06112
Controlled Water Heating		
Monthly Control Charge	$4.80	$4.80
Daily Control Charge	$0.1578	$0.1578
Monthly Control Charge (Seasonal)	$9.60	$9.60
Daily Control Charge (Seasonal)	$0.3156	$0.3156
Rg-RR Residential Response Rewards		
Monthly Fixed Charge	$10.40	$19.00
Daily Fixed Charge	$0.3419	$0.6247
Monthly Fixed Charge (Seasonal)	$20.80	$38.00
Daily Fixed Charge (Seasonal)	$0.6838	$1.2493
Energy Charge (per kWh)		
On-Peak	$0.21477	$0.18704
Off-Peak	$0.06305	$0.06112
Critical Peak	$1.00000	$1.00000
Controlled Water Heating		
Monthly Control Charge	$4.80	$4.80
Daily Control Charge	$0.1578	$0.1578
Monthly Control Charge (Seasonal)	$9.60	$9.60
Daily Control Charge (Seasonal)	$0.3156	$0.3156

Wisconsin Public Service Corporation
SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedule / Rate Class & Description of Rate Components		Present Rates	Authorized Rates
Cg-1 Small Commercial and Industrial Service			
Monthly Fixed Charge	Single-Phase	$12.50	$25.00
Daily Fixed Charge	Single-Phase	$0.4110	$0.8219
Monthly Fixed Charge	Three-Phase	$17.70	$40.00
Daily Fixed Charge	Three-Phase	$0.5819	$1.3151
Monthly Fixed Charge (Seasonal)	Single-Phase	$25.00	$50.00
Daily Fixed Charge (Seasonal)	Single-Phase	$0.8219	$1.6438
Monthly Fixed Charge (Seasonal)	Three-Phase	$35.40	$80.00
Daily Fixed Charge (Seasonal)	Three-Phase	$1.1638	$2.6301
Energy Charge (per kWh)		$0.11727	$0.10730
Cg3-OTOU Small Commercial and Industrial - Optional Time-of-Use			
Monthly Fixed Charge	Single-Phase	$12.50	$25.00
Daily Fixed Charge	Single-Phase	$0.4110	$0.8219
Monthly Fixed Charge	Three-Phase	$17.70	$40.00
Daily Fixed Charge	Three-Phase	$0.5819	$1.3151
Monthly Fixed Charge (Seasonal)	Single-Phase	$25.00	$50.00
Daily Fixed Charge (Seasonal)	Single-Phase	$0.8219	$1.6438
Monthly Fixed Charge (Seasonal)	Three-Phase	$35.40	$80.00
Daily Fixed Charge (Seasonal)	Three-Phase	$1.1638	$2.6301
Energy Charge (per kWh)			
On-Peak		$0.20594	$0.19033
Off-Peak		$0.06507	$0.05976
Controlled Water Heating			
Monthly Control Charge		$4.80	$4.80
Daily Control Charge		$0.1578	$0.1578
Monthly Control Charge (Seasonal)		$9.60	$9.60
Daily Control Charge (Seasonal)		$0.3156	$0.3156

Wisconsin Public Service Corporation
SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedule / Rate Class & Description of Rate Components		Present Rates	Authorized Rates
Cg1-RR Small Commercial and Industrial Response Rewards			
Monthly Fixed Charge	Single-Phase	$12.50	$25.00
Daily Fixed Charge	Single-Phase	$0.4110	$0.8219
Monthly Fixed Charge	Three-Phase	$17.70	$40.00
Daily Fixed Charge	Three-Phase	$0.5819	$1.3151
Monthly Fixed Charge (Seasonal)	Single-Phase	$25.00	$50.00
Daily Fixed Charge (Seasonal)	Single-Phase	$0.8219	$1.6438
Monthly Fixed Charge (Seasonal)	Three-Phase	$35.40	$80.00
Daily Fixed Charge (Seasonal)	Three-Phase	$1.1638	$2.6301
Energy Charge (per kWh)			
On-Peak		$0.21477	$0.20821
Off-Peak		$0.06305	$0.05976
Critical Peak		$1.00000	$1.00000
Controlled Water Heating			
Monthly Control Charge		$4.80	$4.80
Daily Control Charge		$0.1578	$0.1578
Monthly Control Charge (Seasonal)		$9.60	$9.60
Daily Control Charge (Seasonal)		$0.3156	$0.3156
Cg-5 Small Commercial and Industrial Service			
Monthly Fixed Charge	Single-Phase	$31.50	$63.00
Daily Fixed Charge	Single-Phase	$1.0356	$2.0712
Monthly Fixed Charge	Three-Phase	$36.50	$100.80
Daily Fixed Charge	Three-Phase	$1.2000	$3.3140
Monthly Fixed Charge (Seasonal)	Single-Phase	$63.00	$126.00
Daily Fixed Charge (Seasonal)	Single-Phase	$2.0712	$4.1425
Monthly Fixed Charge (Seasonal)	Three-Phase	$73.00	$201.60
Daily Fixed Charge (Seasonal)	Three-Phase	$2.4000	$6.6279
Energy Charge (per kWh)		$0.10202	$0.09723

Wisconsin Public Service Corporation
SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedule / Rate Class & Description of Rate Components		Present Rates	Authorized Rates
Cg5-RR Small Commercial and Industrial Response Rewards			
Monthly Fixed Charge	Single-Phase	$31.50	$63.00
Daily Fixed Charge	Single-Phase	$1.0356	$2.0712
Monthly Fixed Charge	Three-Phase	$36.50	$100.80
Daily Fixed Charge	Three-Phase	$1.2000	$3.3140
Monthly Fixed Charge (Seasonal)	Single-Phase	$63.00	$126.00
Daily Fixed Charge (Seasonal)	Single-Phase	$2.0712	$4.1425
Monthly Fixed Charge (Seasonal)	Three-Phase	$73.00	$201.60
Daily Fixed Charge (Seasonal)	Three-Phase	$2.4000	$6.6279
Energy Charge (per kWh)			
On-Peak		$0.15565	$0.15108
Off-Peak		$0.06226	$0.06043
Critical Peak		$1.00000	$1.00000
Controlled Water Heating			
Monthly Control Charge		$4.80	$4.80
Daily Control Charge		$0.1578	$0.1578
Monthly Control Charge (Seasonal)		$9.60	$9.60
Daily Control Charge (Seasonal)		$0.3156	$0.3156
Cg-20 Commercial and Industrial TOU (100 - 1000 kW)			
Monthly Fixed Charge	Secondary	$59.50	$93.00
Daily Fixed Charge	Secondary	$1.9562	$3.0575
Monthly Fixed Charge	Primary	$113.60	$170.00
Daily Fixed Charge	Primary	$3.7348	$5.5890
Customer Demand Charge (per kW)		$1.689	$1.689
Standby Demand Charge (per kW)		$2.251	$2.251
System Demand Charge (per kW)	Summer	$12.000	$13.243
	Winter	$7.750	$8.830
Energy Charge (per kWh)			
On-Peak		$0.06773	$0.06591
Off-Peak		$0.04080	$0.03991
Energy Limiter (per kWh)		$0.16897	$0.17394

Wisconsin Public Service Corporation
SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedule / Rate Class & Description of Rate Components		Present Rates	Authorized Rates
Cg-20 Commercial and Industrial Response Rewards (100 - 1000 kW)			
Monthly Fixed Charge	Secondary	$59.50	$93.00
Daily Fixed Charge	Secondary	$1.9562	$3.0575
Monthly Fixed Charge	Primary	$113.60	$170.00
Daily Fixed Charge	Primary	$3.7348	$5.5890
Customer Demand Charge (per kW)		$1.689	$1.689
Standby Demand Charge (per kW)		$2.251	$2.251
System Demand Charge (per kW)	Summer	$9.000	$9.932
	Winter	$5.813	$6.623
Energy Charge (per kWh)			
On-Peak		$0.05777	$0.05981
Off-Peak		$0.03542	$0.03592
Critical Peak		$0.40000	$0.40000
Cp Large Commercial and Industrial Service (>1000 kW)			
Monthly Fixed Charge	Secondary	$665.00	$665.00
	Primary	$776.00	$776.00
	Transmission	$1,773.00	$1,773.00
Daily Fixed Charge	Secondary	$21.8630	$21.8630
	Primary	$25.5123	$25.5123
	Transmission	$58.2904	$58.2904
Customer Demand Charge (per kW)	Secondary	$2.260	$2.100
	Primary	$1.990	$1.850
Substation Transformer Capacity Charge (per kVA)	Transmission	$0.633	$0.588
Standby Demand Charge (per kW)	Secondary	$3.50	$3.50
	Primary	$2.75	$2.75
	Transmission	$2.00	$2.00

(Continued on next page)

Wisconsin Public Service Corporation
SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedule / Rate Class & Description of Rate Components		Present Rates	Authorized Rates
Cp LARGE C&I Service (>1000 kW) -- continued			
System Demand Charge (per kW)			
Peak			
Summer	Secondary	$14.080	$15.875
Summer	Primary	$13.712	$15.522
Summer	Transmission	$13.500	$15.309
Winter	Secondary	$7.040	$8.144
Winter	Primary	$6.856	$7.963
Winter	Transmission	$6.750	$7.854
Intermediate			
Summer	Secondary	$10.560	$11.906
Summer	Primary	$10.284	$11.642
Summer	Transmission	$10.125	$11.482
Winter	Secondary	$5.280	$6.108
Winter	Primary	$5.142	$5.972
Winter	Transmission	$5.063	$5.891
Interruptible Demand Charge[1]			
Summer	Secondary	$7.779	$9.574
Summer	Primary	$7.411	$9.221
Summer	Transmission	$7.199	$9.008
Winter	Secondary	$3.889	$4.993
Winter	Primary	$3.705	$4.812
Winter	Transmission	$3.599	$4.703
Interruptible Credit[1]			
Summer		($6.301)	($6.301)
Winter		($3.151)	($3.151)
Note[1] Interruptible Demand = Net of Firm Demand & Interruptible Credit			
Energy Charge (per kWh)			
On-Peak	Secondary	$0.05904	$0.05945
On-Peak	Primary	$0.05784	$0.05771
On-Peak	Transmission	$0.05714	$0.05699
Off-Peak	Secondary	$0.03286	$0.03308
Off-Peak	Primary	$0.03219	$0.03211
Off-Peak	Transmission	$0.03179	$0.03170

Wisconsin Public Service Corporation
SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedule / Rate Class & Description of Rate Components		Present Rates	Authorized Rates
Cp Response Rewards Large Commercial and Industrial Service (>1000 kW)			
Monthly Fixed Charge	Secondary	$665.00	$665.00
	Primary	$776.00	$776.00
	Transmission	$1,773.00	$1,773.00
Daily Fixed Charge	Secondary	$21.8630	$21.8630
	Primary	$25.5123	$25.5123
	Transmission	$58.2904	$58.2904
Customer Demand Charge (per kW)	Secondary	$2.260	$2.100
	Primary	$1.990	$1.850
Substation Transformer Capacity Charge (per kVA)	Transmission	$0.633	$0.588
Standby Demand Charge (per kW)	Secondary	$3.50	$3.50
	Primary	$2.75	$2.75
	Transmission	$2.00	$2.00
System Demand Charge (per kW)			
Peak			
Summer	Secondary	$10.560	$11.906
Summer	Primary	$10.284	$11.642
Summer	Transmission	$10.125	$11.482
Winter	Secondary	$5.280	$6.108
Winter	Primary	$5.142	$5.972
Winter	Transmission	$5.063	$5.891
Intermediate			
Summer	Secondary	$7.920	$8.930
Summer	Primary	$7.713	$8.731
Summer	Transmission	$7.594	$8.611
Winter	Secondary	$3.960	$4.581
Winter	Primary	$3.857	$4.479
Winter	Transmission	$3.797	$4.418

(Continued on next page)

Wisconsin Public Service Corporation
SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedule / Rate Class & Description of Rate Components		Present Rates	Authorized Rates
Cp Response Rewards Large C&I Service (>1000 kW) -- continued			
Interruptible Demand Charge[1]			
Summer	Secondary	$4.259	$5.605
Summer	Primary	$3.983	$5.341
Summer	Transmission	$3.824	$5.181
Winter	Secondary	$2.129	$2.957
Winter	Primary	$1.991	$2.821
Winter	Transmission	$1.912	$2.740
Interruptible Credit[1]			
Summer		($6.301)	($6.301)
Winter		($3.151)	($3.151)
Note[1] Interruptible Demand = Net of Firm Demand & Interruptible Credit			
Energy Charge (per kWh)			
On-Peak	Secondary	$0.03917	$0.04050
On-Peak	Primary	$0.03837	$0.03931
On-Peak	Transmission	$0.03790	$0.03882
Off-Peak	Secondary	$0.02956	$0.02976
Off-Peak	Primary	$0.02896	$0.02889
Off-Peak	Transmission	$0.02861	$0.02853
Critical Peak	Secondary	$0.40000	$0.40000
Critical Peak	Primary	$0.39185	$0.38827
Critical Peak	Transmission	$0.38709	$0.38340
Cp Next Day (Closed to New Customers)			
Monthly Fixed Charge	Secondary	$665.00	$665.00
	Primary	$776.00	$776.00
	Transmission	$1,773.00	$1,773.00
Daily Fixed Charge	Secondary	$21.8630	$21.8630
	Primary	$25.5123	$25.5123
	Transmission	$58.2904	$58.2904
Customer Demand Charge (per kW)	Secondary	$2.260	$2.100
	Primary	$1.990	$1.850
Substation Transformer Capacity Charge (per kVA)	Transmission	$0.633	$0.588
Standby Demand Charge (per kW)	Secondary	$3.50	$3.50
	Primary	$2.75	$2.75
	Transmission	$2.00	$2.00

(Continued on next page)

Wisconsin Public Service Corporation
SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedule / Rate Class & Description of Rate Components		Present Rates	Authorized Rates
Cp Next Day (Closed to New Customers) -- continued			
System Demand Charge (per kW)			
Peak			
Summer	Secondary	$14.080	$15.875
Summer	Primary	$13.712	$15.522
Summer	Transmission	$13.500	$15.309
Winter	Secondary	$7.040	$8.144
Winter	Primary	$6.856	$7.963
Winter	Transmission	$6.750	$7.854
Intermediate			
Summer	Secondary	$10.560	$11.906
Summer	Primary	$10.284	$11.642
Summer	Transmission	$10.125	$11.482
Winter	Secondary	$5.280	$6.108
Winter	Primary	$5.142	$5.972
Winter	Transmission	$5.063	$5.891
Energy Charge (per kWh)			
Critical Day	Secondary	$0.10006	$0.09045
Critical Day	Primary	$0.09802	$0.08780
Critical Day	Transmission	$0.09683	$0.08670
Peak Day	Secondary	$0.06718	$0.06682
Peak Day	Primary	$0.06581	$0.06486
Peak Day	Transmission	$0.06501	$0.06405
Mid-Economy Day	Secondary	$0.05466	$0.05559
Mid-Economy Day	Primary	$0.05355	$0.05396
Mid-Economy Day	Transmission	$0.05290	$0.05328
Economy Day	Secondary	$0.04614	$0.04848
Economy Day	Primary	$0.04520	$0.04706
Economy Day	Transmission	$0.04465	$0.04647
Off-Peak	Secondary	$0.03286	$0.03308
Off-Peak	Primary	$0.03219	$0.03211
Off-Peak	Transmission	$0.03179	$0.03170

Wisconsin Public Service Corporation
SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedule / Rate Class & Description of Rate Components	Present Rates	Authorized Rates
Ls-1 Outdoor Overhead Lighting		
Company Owned		
Sodium Vapor		
5,670 Lumens (70W)	$17.00	$17.00
9,000 Lumens (100W)	$17.52	$17.52
14,000 Lumens (150W)	$20.00	$20.00
27,000 Lumens (250W)	$24.65	$24.65
45,000 Lumens (400W)	$33.06	$33.06
9,000 Lumens (100W) - Area	$12.93	$14.65
14,000 Lumens (150W) - Area	$15.76	$17.96
27,000 Lumens (250W) - Directional	$29.90	$29.90
45,000 Lumens (400W) - Directional (Closed)	$36.56	$36.56
Metal Halide		
8,500 Lumens (150W)	$23.55	$23.55
26,000 Lumens (350W)	$29.88	$29.88
36,000 Lumens (400W) - (Closed)	$33.06	$33.06
26,000 Lumens (350W) - Directional	$31.91	$31.91
36,000 Lumens (400W) - Directional (Closed)	$36.30	$36.30
110,000 Lumens (1000W) - Directional	$55.00	$55.00
LED		
9,000 Lumens (100W) SV equivalent	$17.52	$14.47
14,000 Lumens (150W) SV equivalent	$20.00	$18.23
27,000 Lumens (250W) SV equivalent	$24.65	$23.83
Customer Owned (Closed to New Customers)		
Sodium Vapor		
9,000 Lumens (100W)	$11.96	$11.96
14,000 Lumens (150W)	$14.08	$14.08
27,000 Lumens (250 W)	$18.00	$18.00
45,000 Lumens (400W)	$22.04	$22.04
Metal Halide		
8500 Lumens (150W)	$16.82	$16.82
26,000 Lumens (350W)	$21.04	$21.04

(Continued on next page)

Wisconsin Public Service Corporation
SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedule / Rate Class & Description of Rate Components	Present Rates	Authorized Rates
Ls-1 Outdoor Overhead Lighting -- continued		
Non-Standard Facilities		
Wood Poles	$5.08	$5.08
Fiberglass Poles 25' / 20'	$8.47	$8.47
Fiberglass Poles 30' / 35'	$10.94	$10.94
Fiberglass Poles 35' / 30'	$13.70	$13.70
Fiberglass Poles 40' / 35'	$22.79	$22.79
Spans	$2.24	$2.24
Excess Footage - Mast Arm	$0.23	$0.23
Ms-31 MUNICIPAL ORNAMENTAL LIGHTING - Cancelled		
Energy Charge (per kWh)	$0.06528	$0.00000
NATUREWISE		
NAT-R	$2.40	$2.40
NAT-C	$2.40	$2.40
ATS - AUTOMATIC TRANSFER SWITCH		
Fixed Charge		
Total Charge	$667.00	$671.00
Maintenance Only	$230.00	$232.84
Electric Revenue Stabilization Mechanism - 2013 Rate Adjustments[1]		
Residential & Commercial Non-Demand Classes:		
Rg-1 thru Rg-5, Cg-1 thru Cg-5		-$0.00055
Medium Commercial (Demand Metered) Class:		
Cg-20		-$0.00080

Note[1] -- Revenue Stabilization Mechanism Adjustments are included in the energy charges listed above and sunset on December 31, 2015.

Wisconsin Public Service Corporation
SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedule / Rate Class & Description of Rate Components		Present Rates	Authorized Rates
PG-2A Parallel Generation - Purchase by WPSC			
Monthly Fixed Charge		$20.00	$20.00
Daily Fixed Charge		$0.6575	$0.6575
Energy Credit (per kWh)			
On-Peak	Secondary	($0.03821)	($0.05247)
On-Peak	Primary	($0.03902)	($0.05359)
On-Peak	Transmission	($0.03865)	($0.05308)
Off-Peak	Secondary	($0.02609)	($0.03353)
Off-Peak	Primary	($0.02664)	($0.03425)
Off-Peak	Transmission	($0.02639)	($0.03392)
Interruptible Energy Credit (per kWh)			
On-Peak	Secondary	($0.05904)	($0.05945)
On-Peak	Primary	($0.05784)	($0.05771)
On-Peak	Transmission	($0.05714)	($0.05699)
Off-Peak	Secondary	($0.03286)	($0.03308)
Off-Peak	Primary	($0.03219)	($0.03211)
Off-Peak	Transmission	($0.03179)	($0.03170)
PG-2B Parallel Generation - Purchase by WPSC (LMP)			
Monthly Fixed Charge		$20.00	$20.00
Daily Fixed Charge		$0.6575	$0.6575
Energy Credit (per kWh)		Market	Market
PG-Solar Parallel Generation - Purchase by WPSC (Solar)			
Monthly Fixed Charge		$2.00	$2.00
Daily Fixed Charge		$0.0658	$0.0658
Energy Credit (per kWh)		($0.25000)	($0.25000)

Wisconsin Public Service Corporation
SUMMARY OF ELECTRIC RATE CHANGES

Rate Schedule / Rate Class & Description of Rate Components		Present Rates	Authorized Rates
PG-BioGas Parallel Generation - Purchase by WPSC (BioGas)			
Monthly Fixed Charge	Secondary	$30.50	$30.50
Daily Fixed Charge	Secondary	$1.0027	$1.0027
Monthly Fixed Charge	Primary	$58.30	$58.30
Daily Fixed Charge	Primary	$1.9167	$1.9167
Energy Credit (per kWh)			
On-Peak	Secondary	($0.10355)	($0.10355)
On-Peak	Primary	($0.10645)	($0.10645)
On-Peak	Transmission	($0.10500)	($0.10500)
Off-Peak	Secondary	($0.05917)	($0.05917)
Off-Peak	Primary	($0.06083)	($0.06083)
Off-Peak	Transmission	($0.06000)	($0.06000)
PG-4 Parallel Generation - Net Energy Billing			
Energy Credit (per kWh)		($0.03985)	($0.05036)
Act 141 Cost in Base Rates (per kWh)			
Residential		($0.00198)	($0.00202)
Commercial and Industrial		($0.00175)	($0.00178)
Approx. Act 141 $ in Large Energy Customer Rates		Specific to each customer	
Electric Embedded Allowances ($ per customer except as noted)			
Residential Customers (Rg-1 thru Rg-5)			
Year-Round Customers		$425.00	$425.00
Seasonal Customers		$213.00	$213.00
Commercial & Industrial (Cg under 100 kW)			
Estimated Demand of 0 to 15 kW			
Year-Round Customers		$425.00	$425.00
Seasonal Customers		$213.00	$213.00
Estimated Demand of 16 to 50 kW			
Year-Round Customers		$1,060.00	$1,060.00
Seasonal Customers		$530.00	$530.00
Estimated Demand of 51 kW & over			
Year-Round Customers		$2,470.00	$2,470.00
Seasonal Customers		$1,235.00	$1,235.00
Commercial & Industrial (Cg over 100 kW & Cp)	$ per kW	$27.00	$27.00

Wisconsin Public Service Corporation

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Residential		
Daily Customer Charge - (Rg-3)	$ 0.3370	$ 0.5589
Daily Customer Charge - Seasonal Service (Rg-3)	$ 0.6740	$ 1.1178
Daily Customer Charge - (Rg-T)	$ 0.3370	$ 0.5589
Telemetering Charge (Cg-Rg-T)	$ 0.3814	$ 0.3945
Daily Transportaion Administrative Charge (Rg-T)	$ 1.2329	$ 1.2329
Volumetric Charges:		
Distribution Service Charge - (Rg-3)	$ 0.1824	$ 0.0610
Distribution Service Charge - (Rg-T)	$ 0.1824	$ 0.0610
Daily Balancing Charge	$ 0.0007	$ 0.0005
Gas Acquisition Charge (Rg-3)	$ 0.0257	$ 0.0196
Standard Commercial (Cg-FST, Annual Usage < 2,000 therms)		
Daily Customer Charge	$ 0.3370	$ 0.5589
Daily Customer Charge - Seasonal	$ 0.6740	$ 1.1178
Volumetric Charges:		
Distribution Service Charge	$ 0.1824	$ 0.0610
Daily Balancing Charge	$ 0.0007	$ 0.0005
Gas Acquisition Charge	$ 0.0257	$ 0.0196
Small Commercial (Annual Usage 2,001 - 20,000 therms)		
Daily Customer Charge - (Cg-FS)	$ 0.9863	$ 0.9863
Daily Customer Charge - Seasonal (Cg-FS)	$ 1.9726	$ 1.9726
Daily Customer Charge - (Cg-TS, TSA)	$ 0.9863	$ 0.9863
Telemetering Charge (Cg-TS)	$ 0.3814	$ 0.3945
Transportation Administrative Charge (Cg-TS, CG-TSA)	$ 1.2329	$ 1.2329
Volumetric Charges:		
Distribution Service Charge - (Cg-FS)	$ 0.0949	$ 0.0927
Distribution Service Charge - (Cg-TS, TSA)	$ 0.1094	$ 0.0927
Daily Balancing Charge	$ 0.0007	$ 0.0005
Gas Acquisition Charge (Cg-FS)	$ 0.0238	$ 0.0162

Wisconsin Public Service Corporation

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Medium Commercial (Annual Usage 20,001 - 200,000 therms)		
Daily Customer Charge - (Cg-FM)	$ 4.4384	$ 4.9315
Daily Customer Charge - Seasonal (Cg-FM)	$ 8.8768	$ 9.8630
Daily Customer Charge - (Cg-IM, Cg-SOS-M, TM, TMA, IEGM)	$ 4.4384	$ 4.9315
Telemetering Charge (Cg-IM, Cg-TM, IEGM)	$ 0.3814	$ 0.3945
Transportation Administrative Charge (Cg-TM, Cg-TMA)	$ 1.2329	$ 1.2329
Volumetric Charges:		
Distribution Service Charge (FM)	$ 0.0652	$ 0.0708
Distribution Service Charge - (Cg-IM, Cg-SOS-M, TM, TMA, IEGM	$ 0.0750	$ 0.0708
Daily Balancing Charge	$ 0.0007	$ 0.0005
Gas Acquisition Charge (Gc-FM)	$ 0.0238	$ 0.0149
Gas Acquisition Charge (Gc-IM, Cg-SOS-M, IEGM)	$ 0.0199	$ 0.0126
Large Commercial (200,001 to 2,400,000)		
Daily Customer Charge	$ 19.5616	$ 20.3836
Daily Customer Charge - Seasonal (Cg-FL)	$ 39.1232	$ 40.7672
Telemetering Charge (Cg-FL, Cg-IL, Cg-TL, Cg-SOS-L)	$ 0.3814	$ 0.3945
Transportation Administrative Charge (Cg-TL, Cg-TLA)	$ 1.2329	$ 1.2329
Demand Charge	$ 0.1475	$ 0.1475
Volumetric Charges:		
Distribution Service Charge	$ 0.0336	$ 0.0342
Daily Balancing Charge	$ 0.0007	$ 0.0005
Gas Acquisition Charge (Cg-FL)	$ 0.0170	$ 0.0115
Gas Acquisition Charge (Cg-IL, Cg-SOS-L)	$ 0.0155	$ 0.0105
S-Large Commercial (> 2,400,000)		
Daily Basic Distribution Charge	$ 127.6274	$ 127.6274
Telemetering Charge (Cg-ISL, Cg-TSL)	$ 0.3814	$ 0.3945
Transportation Administrative Charge (Cg-TSL, Cg-TSLA)	$ 1.2329	$ 1.2329
Demand Charge	$ 0.0833	$ 0.1000
Volumetric Charges:		
Distribution Service Charge	$ 0.0271	$ 0.0215
Daily Balancing Charge	$ 0.0007	$ 0.0005
Gas Acquisition Charge (Cg-ISL)	$ 0.0155	$ 0.0066

Wisconsin Public Service Corporation

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Interruptible Electric Generation (>200,000)		
Daily Basic Distribution Charge	$ 229.9726	$ 229.9726
Telemetering Charge	$ 0.3814	$ 0.3945
Demand Charge	$ 0.0649	$ 0.0662
Volumetric Charges:		
Distribution Service Charge	$ 0.0109	$ 0.0131
Daily Balancing Charge	$ 0.0007	$ 0.0005
Gas Acquisition Charge	$ 0.0131	$ 0.0080
Coal Displacement Gas Transportation		
Daily Basic Distribution Charge	$ 127.6274	$ 127.6274
Telemetering Charge	$ 0.3814	$ 0.3945
Transportation Administrative Charge (CDGT)	$ 1.2329	$ 1.2329
Demand Charge	$ 0.0833	$ 0.1000
Volumetric Charges:		
Distribution Service Charge (CDGT)	$ 0.0237	$ 0.0215
Daily Balancing Charge	$ 0.0007	$ 0.0005
Base Average Cost of Gas Rates:		
Commodity ("Comm") rate	$ 0.3594	$ 0.4412
Peak Day Demand ("D1") rate	$ 0.1350	$ 0.1226
Annual Demand ("D2") rate	$ 0.0083	$ 0.0098
Balancing ("Bal") rate	$ 0.0062	$ 0.0050

Wisconsin Public Service Corporation

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Act 141 Volumetric Distribution Rates 1/		
Residential (Rg-3)	$ 0.0092	$ 0.0071
Commercial & Industrial, Cg-ST (0 to 2,000)	$ 0.0094	$ 0.0063
Commercial & Industrial, Cg-S (2,001 to 20,000)	$ 0.0094	$ 0.0063
Commercial & Industrial, Cg-M (20,001 to 200,000)	$ 0.0094	$ 0.0063
Commercial & Industrial, Cg-L (200,001 to 2,400,000)	$ 0.0094	$ 0.0063
Commercial & Industrial, Cg-SL (> 2,400,000)	$ 0.0094	$ 0.0063
Interruptible Electric Generation, Cg-IEG (200,000+)	$ 0.0094	$ 0.0063
Coal Displacement Gas Transportation (CDGT)	$ 0.0094	$ 0.0063

1/ Act 141 volumetric distribution rates are included in the above volumetric Distribution Service Charges.

	Present Rates	Authorized Rates
Gas Revenue Stabilization Mechanism - 2015 Rate Adjustment 2/		
Residential (Rg-3)	$ -	$ (0.0283)
Commercial & Industrial, Cg-FST (0 to 2,000)	$ -	$ (0.0283)
Commercial & Industrial, Cg-FS (2,001 to 20,000)	$ -	$ (0.0089)
Commercial & Industrial, Cg-FM (20,001 to 200,000)	$ -	$ (0.0089)

2/ Gas Revenue Stabilization Mechanism Adjustments are not included in the above volumetric distribution service charges and sunset on December 31, 2015.

Gas Revenue Summary

Service Rate Classes	Volumes	Current Margin & Admin Revenues	+ Cost of Gas Revenues	= Rebundled Service Class Revenues	+ Authorized Distribution Rev Change/Class	= Total Bundled Rev. by Dist. Class	Percent Change Rebundled w/COG	Percent Change Rebundled w/o COG
Residential								
Residential (Rg-3)	224,766,350	$ 81,601,051	$ 125,082,367	$ 206,683,418	$ (12,233,395)	$ 194,450,023	(5.92)%	(14.99)%
Residential - Seasonal (Rg-3)	1,136,869	$ 685,611	$ 518,382	$ 1,203,993	$ 117,820	$ 1,321,813	9.79%	17.18%
Subtotal	225,903,219	$ 82,286,662	$ 125,600,749	$ 207,887,411	$ (12,115,575)	$ 195,771,836	(5.83)%	(14.72)%
Commercial & Industrial, Cg-ST (0 to 2,000)								
Firm Commercial (Cg-FST)	17,764,824	$ 6,202,450	$ 10,020,012	$ 16,222,462	$ (1,129,876)	$ 15,092,586	(6.96)%	(18.22)%
Seasonal Commercial (Cg-FST)	28,866	$ 13,899	$ 13,162	$ 27,061	$ 681	$ 27,742	2.52%	4.90%
Subtotal Cg-ST	17,793,690	$ 6,216,349	$ 10,033,174	$ 16,249,523	$ (1,129,195)	$ 15,120,328	(6.95)%	(18.16)%
Commercial & Industrial, Cg-S (2,001 to 20,000)								
Firm Commercial (Cg-FS)	73,785,945	$ 13,308,825	$ 40,969,212	$ 54,278,037	$ (1,388,069)	$ 52,889,968	(2.56)%	(10.43)%
Seasonal Commercial (Cg-FS)	18,867	$ 5,733	$ 8,603	$ 14,336	$ (357)	$ 13,979	(2.49)%	(6.22)%
Transport Commercial (Cg-TS)	141,735	$ 23,120		$ 23,120	$ (2,357)	$ 20,762	(10.20)%	(10.20)%
Transport-A Commercial (Cg-TSA)	398,396	$ 76,399		$ 76,399	$ (6,733)	$ 69,666	(8.81)%	(8.81)%
Interdepartmental (Cg-FS)	-	$ -	$ -	$ -	$ -	$ -	0.00%	0.00%
Subtotal Cg-S	74,344,943	$ 13,414,076	$ 40,977,815	$ 54,391,891	$ (1,397,516)	$ 52,994,375	(2.57)%	(10.42)%
Commercial & Industrial, Cg-M (20,001 to 200,000)								
Firm Commercial (Cg-FM)	53,476,851	$ 6,464,409	$ 29,266,177	$ 35,730,586	$ (461,087)	$ 35,269,499	(1.29)%	(7.13)%
Seasonal Commercial (Cg-FM)	-	$ -	$ -	$ -	$ -	$ -	0.00%	0.00%
Interruptible Commercial (Cg-IM)	1,591,739	$ 191,195	$ 725,791	$ 916,986	$ (13,744)	$ 903,241	(1.50)%	(7.19)%
Transport Commercial (Cg-TM)	24,088,341	$ 2,310,682		$ 2,310,682	$ (55,921)	$ 2,254,760	(2.42)%	(2.42)%
Transport-A Commercial (Cg-TMA)	8,490,496	$ 992,739		$ 992,739	$ (6,342)	$ 986,397	(0.64)%	(0.64)%
Season-Opp Commercial (Cg-SOS-M)	346,315	$ 174,049	$ 157,910	$ 331,960	$ 11,607	$ 343,566	3.50%	6.67%
Interruptible Electric Generation (Cg-IEGM)	-	$ -	$ -	$ -	$ -	$ -	0.00%	0.00%
Subtotal Cg-M	87,993,742	$ 10,133,073	$ 30,149,879	$ 40,282,952	$ (525,488)	$ 39,757,464	(1.30)%	(5.19)%
Commercial & Industrial, Cg-L (200,001 to 2,400,000)								
Firm Commercial (Cg-FL)	11,629,335	$ 928,456	$ 6,091,485	$ 7,019,941	$ (34,606)	$ 6,985,335	(0.49)%	(3.73)%
Interruptible Commercial (Cg-IL)	2,221,946	$ 140,453	$ 1,013,148	$ 1,153,602	$ (7,513)	$ 1,146,089	(0.65)%	(5.35)%
Transport Commercial (Cg-TL)	150,826,925	$ 7,504,563		$ 7,504,563	$ 352,186	$ 7,856,749	4.69%	4.69%
Transport-A Commercial (Cg-TLA)	1,193,245	$ 81,163		81163.461	$ 1,377	$ 82,541	1.70%	1.70%
Subtotal Cg-L	165,871,451	$ 8,654,636	$ 7,104,634	$ 15,759,270	$ 311,444	$ 16,070,713	1.98%	3.60%
Commercial & Industrial, Cg-SL (> 2,400,000)								
Subtotal Cg-SL	198,739,000	$ 6,208,561	$ -	$ 6,208,561	$ (460,526)	$ 5,748,035	(7.42)%	(7.42)%
Interruptible Electric Generation, Cg-IEG (200,000+)								
Power Department (Cg-IEG)	33,492,336	$ 2,276,385	$ 15,271,617	$ 17,548,002	$ (94,111)	$ 17,453,891	(0.54)%	(4.13)%
Coal Displacement Gas Transportation (CDGT)	19,500,001	$ 418,675		$ 418,675	$ 29,298	$ 447,973	7.00%	7.00%
Total Gas Sales Revenues	823,638,382	$ 129,608,416	$ 229,137,868	$ 358,746,284	$ (15,381,669)	$ 343,364,614	(4.29)%	(11.87)%
Plus:								
Other Gas Revenue				$ 9,309,873		$ 9,309,873		
Total Gas Operating Revenue				$ 368,056,157		$ 352,674,487	(4.18)%	

Monthly Residential Bill Impact Analysis

Gas Costs	Summer	Winter
Firm Sales Service	0.4560	0.5786

	2014 Rates with GRSM Charge				**2015 Rates without GRSM Charges**				**Authorized Rates with 2015 GRSM Credit**				**Monthly Percent Increase (Decrease)**	**Monthly Percent Increase (Decrease)**
Monthly Use Therms	**Customer Charge**	**Admin. & Distribut'n Charges**	**Gas Costs**	**Total Costs**	**Customer Charge**	**Admin. & Distribut'n Charges**	**Gas Costs**	**Total Costs**	**Admin. & Customer Charges**	**Admin. & Distribut'n Charges**	**Gas Costs**	**Total Costs**	**2014**	**2015**
Rg-1: Residential Firm Sales Service During Summer Months														
5	$ 10.25	$ 1.18	$ 2.28	$ 13.71	$ 10.25	$ 1.04	$ 2.28	$ 13.57	$ 17.00	$ 0.26	$ 2.28	$ 19.54	42.54%	43.98%
15	$ 10.25	$ 3.54	$ 6.84	$ 20.63	$ 10.25	$ 3.13	$ 6.84	$ 20.22	$ 17.00	$ 0.79	$ 6.84	$ 24.63	19.38%	21.81%
26	$ 10.25	$ 5.67	$ 10.94	$ 26.86	$ 10.25	$ 5.01	$ 10.94	$ 26.20	$ 17.00	$ 1.27	$ 10.94	$ 29.21	8.74%	11.47%
35	$ 10.25	$ 8.27	$ 15.96	$ 34.48	$ 10.25	$ 7.31	$ 15.96	$ 33.52	$ 17.00	$ 1.85	$ 15.96	$ 34.81	0.96%	3.85%
50	$ 10.25	$ 11.81	$ 22.80	$ 44.86	$ 10.25	$ 10.44	$ 22.80	$ 43.49	$ 17.00	$ 2.64	$ 22.80	$ 42.44	(5.40)%	(2.42)%
75	$ 10.25	$ 17.72	$ 34.20	$ 62.16	$ 10.25	$ 15.66	$ 34.20	$ 60.11	$ 17.00	$ 3.96	$ 34.20	$ 55.16	(11.27)%	(8.24)%
106	$ 10.25	$ 25.51	$ 49.25	$ 85.01	$ 10.25	$ 22.55	$ 49.25	$ 82.05	$ 17.00	$ 5.70	$ 49.25	$ 71.95	(15.36)%	(12.31)%
125	$ 10.25	$ 29.53	$ 57.00	$ 96.77	$ 10.25	$ 26.10	$ 57.00	$ 93.35	$ 17.00	$ 6.60	$ 57.00	$ 80.60	(16.72)%	(13.66)%
150	$ 10.25	$ 35.43	$ 68.40	$ 114.08	$ 10.25	$ 31.32	$ 68.40	$ 109.97	$ 17.00	$ 7.92	$ 68.40	$ 93.32	(18.20)%	(15.14)%
200	$ 10.25	$ 47.24	$ 91.19	$ 148.69	$ 10.25	$ 41.76	$ 91.19	$ 143.21	$ 17.00	$ 10.56	$ 91.19	$ 118.75	(20.13)%	(17.07)%
300	$ 10.25	$ 70.86	$ 136.79	$ 217.90	$ 10.25	$ 62.64	$ 136.79	$ 209.68	$ 17.00	$ 15.84	$ 136.79	$ 169.63	(22.15)%	(19.10)%
Rg-1: Residential Firm Sales Service During Winter Months														
5	$ 10.25	$ 1.18	$ 2.89	$ 14.32	$ 10.25	$ 1.04	$ 2.89	$ 14.19	$ 17.00	$ 0.26	$ 2.89	$ 20.16	40.72%	42.08%
15	$ 10.25	$ 3.54	$ 8.68	$ 22.47	$ 10.25	$ 3.13	$ 8.68	$ 22.06	$ 17.00	$ 0.79	$ 8.68	$ 26.47	17.79%	19.99%
26	$ 10.25	$ 5.67	$ 13.89	$ 29.81	$ 10.25	$ 5.01	$ 13.89	$ 29.15	$ 17.00	$ 1.27	$ 13.89	$ 32.15	7.88%	10.31%
35	$ 10.25	$ 8.27	$ 20.25	$ 38.77	$ 10.25	$ 7.31	$ 20.25	$ 37.81	$ 17.00	$ 1.85	$ 20.25	$ 39.10	0.85%	3.41%
50	$ 10.25	$ 11.81	$ 28.93	$ 50.99	$ 10.25	$ 10.44	$ 28.93	$ 49.62	$ 17.00	$ 2.64	$ 28.93	$ 48.57	(4.75)%	(2.12)%
75	$ 10.25	$ 17.72	$ 43.39	$ 71.36	$ 10.25	$ 15.66	$ 43.39	$ 69.30	$ 17.00	$ 3.96	$ 43.39	$ 64.35	(9.82)%	(7.14)%
106	$ 10.25	$ 25.51	$ 62.49	$ 98.25	$ 10.25	$ 22.55	$ 62.49	$ 95.29	$ 17.00	$ 5.70	$ 62.49	$ 85.19	(13.29)%	(10.60)%
125	$ 10.25	$ 29.53	$ 72.32	$ 112.10	$ 10.25	$ 26.10	$ 72.32	$ 108.67	$ 17.00	$ 6.60	$ 72.32	$ 95.92	(14.43)%	(11.73)%
150	$ 10.25	$ 35.43	$ 86.79	$ 132.47	$ 10.25	$ 31.32	$ 86.79	$ 128.36	$ 17.00	$ 7.92	$ 86.79	$ 111.71	(15.67)%	(12.97)%
200	$ 10.25	$ 47.24	$ 115.72	$ 173.21	$ 10.25	$ 41.76	$ 115.72	$ 167.73	$ 17.00	$ 10.56	$ 115.72	$ 143.28	(17.28)%	(14.58)%
300	$ 10.25	$ 70.86	$ 173.58	$ 254.69	$ 10.25	$ 62.64	$ 173.58	$ 246.47	$ 17.00	$ 15.84	$ 173.58	$ 206.42	(18.95)%	(16.25)%
Avg. Annual Residential Billing														
792	$ 123.01	$ 187.07	$ 440.59	$ 750.66	$ 123.01	$ 165.37	$ 440.59	$ 728.96	$ 204.00	$ 41.82	$ 440.59	$ 686.40	(8.56)%	(5.84)%

P.S.C.W. Volume No. 8 9~~8~~th Rev. Sheet No. G4.03
Replaces 8~~7~~th Rev. Sheet No. G4.03
Amendment xxx~~605~~ Schedule CURT

Customer Attachment, Enlargement & Curtailment Procedure **Natural Gas**

Continued from Sheet No. G4.02.

2. On a specific day, the Company may deviate from Section 2.C. below and declare a Selective Constraint Day as provided for in rate schedule GT.

3. If any customer notifies the Company in writing that a Curtailment will result in emergency conditions or shutdown of operations, the Company may depart from the priorities listed below and allow that customer to use gas when he would normally be Curtailed. The Company shall be under no obligation to grant emergency adjustments to the Curtailment plan but shall make such adjustments when, in the Company's sole judgment, conditions warrant it.

4. The Company will file a report with the Commission after each Curtailment or Constraint. The report will be filed on a public, non-confidential basis, and shall be received by the Commission within 30 days following the Curtailment or Constraint.

C. Curtailment Schedule:

1. Curtail Cg-SOS-L and Cg-SOS-M customers.

2. Declare a High-Flow Constraint Day for CDGT, CSR-S, CSR-M, CSR-L and CSR-SL customers.

3. Declare a High-Flow Constraint Day for all Rg-T, Cg-TS, Cg-TSA, Cg-TM, Cg-TMA, Cg-TL, Cg-TLA, Cg-TSL, Cg-TSLA, Cg-TEGS, Cg-TEGM, Cg-TEGL, and Cg-TEGSL customers.

~~R~~ 4. Curtail Interruptible Customers in the following order:
R a. Cg-ISL,~~ and~~ Cg-IEGL, and Cg-IEGM on a pro-
R rata basis up to full interruption of service ~~(Above FT~~
R ~~Contract Volumes only)~~
R b. Cg-IL ~~(Above FT Contract Volumes only)~~
R c. Cg-IM ~~(Above FT Contract Volumes only)~~
~~D~~

Continued to Sheet No. G4.04.

P.S.C.W. Volume No. 8 | 7~~6~~th Rev. Sheet No. G7.04
Replaces 6~~5~~th Rev. Sheet No. G7.04
Amendment xxx~~672~~ Schedule GCg-I

Commercial and Industrial Interruptible Service **Natural Gas**

Continued from Sheet No. G7.03.

~~N~~ A. The switch date, requirement from Section 8.K above may be waived by the Company, in the Company's sole discretion, due to a significant change in the customer's existing gas account usage pattern, if the Company has adequate gas supply and interstate pipeline capacity to serve the customer's additional usage, and the Company anticipates no significant detriment to existing system sales customers. If the Company waives the switch date requirement, the Company may require the customer to pay an exit fee to recover the costs related to a switch to or from service under this rate schedule. This exit fee may include, but is not limited to, any above market gas commodity costs, any interstate pipeline transportation and/or storage costs, and any other demand costs.

~~R~~

B. If a customer fails to interrupt when required by the Company, the customer will be subject to a mandatory full interruption test. During a full interruption test, the customer will be required to switch to their alternate fuel system and successfully operate the alternate fuel system or suspend the use of gas for a minimum of 4 hours. If the customer fails two successive full interruption tests after the initial interruption, or the customer fails to interrupt two or more times during a 12 month rolling time period when required by the Company, the Company reserves the right to move the customer ~~customer will be moved~~ to the appropriate firm service schedule. The customer will remain on the firm service schedule for a minimum of one year and will only be allowed to return to the interruptible service schedule when it can demonstrate the ability to interrupt gas usage when required.

R

~~R~~

C. The Company will install remote metering devices to monitor gas consumption. The customer shall provide, at the Company's request, an uninterrupted supply of 120V AC electricity at the gas metering site for these devices.

~~R~~

D. Gas sales under this rate schedule by the WPSC gas utility to the WPSC electric utility for purposes of electrical generation shall be billed at the Cg-IEG rate, and shall include any fixed or demand charges.

~~R~~

E. Service under all Cg-IEG Customer Classes are restricted to those customers using gas for the purpose of generating electrical energy for resale, and any customer taking service under this rate schedule using gas for the purpose of generating electrical energy for resale must take service under one of the Cg-IEG Customer Classes. Gas used for plant startup only, while no electricity is being generated, does not qualify the customer for service under any of the Cg-IEG Customer Classes.

P.S.C.W. Volume No. 8 | 1st Rev.~~Original~~ Sheet No. G7.14
Replaces Original Sheet No. G7.14
Amendment xxx~~527~~ Schedule CgSOS

Comm and Ind Interruptible Service-Seasonal Opportunity Sales Natural Gas

~~R~~ Continued from Sheet No. G7.13.

F. If a customer fails to interrupt when required by the Company, the customer will be subject to a mandatory full interruption test. During a full interruption test, the customer will be required to switch to their alternate fuel system and successfully operate the alternate fuel system or suspend the use of gas for a minimum of 4 hours. If the customer fails two successive full interruption tests after the initial interruption, or the customer fails to interrupt two or more times during a 12 month rolling time period when required by the Company, the Company reserves the right to move the customer ~~will be moved~~ to the appropriate firm service schedule. The customer will remain on the firm service schedule for a minimum of one year and will only be allowed to return to the interruptible service schedule when it can demonstrate the ability to interrupt gas usage when required.

~~R~~ G. The Company will install remote metering devices to monitor gas consumption. The customer shall provide, at the Company's request, an uninterrupted supply of 120V AC electricity at the gas metering site for these devices.

H. If a customer uses 30 Therms or less since the last issued bill, no Customer Charge will be billed, no bill will be issued, and all Therms will be charged on the next issued bill.

P.S.C.W. Volume No. 8 | 16~~5~~th Rev. Sheet No. G11.02
Replaces 15~~4~~th Rev. Sheet No. G11.02
Amendment xxx~~707~~ Schedule ERNG

Extension Rules **Natural Gas**

Continued from Sheet No. G11.01.

C. The following values shall be used to determine the estimated costs for gas main extensions:

~~R~~ R = Nominal gas main diameter:
2" or less: $6.98 per foot
>2":
Estimated cost in the Company's sole discretion.

D. If more than one customer requests a gas main extension, any required advance payment for gas main will normally be apportioned equally among the customers to be connected. If such apportionment would be inequitable, other factors, such as relative consumption and/or location of customers along the gas main extension, shall be considered.

E. A gas main extension shall normally be located along the most direct and practical route in the public right-of-way from the nearest existing distribution gas main adequate to serve the customer's forecasted load to a point in the right-of-way on which the structure fronts, directly opposite the meter location. Both the main and meter locations will be established by Company standards, in the Company's sole discretion.

F. The calculation of a customer's payment shall be restricted to a tract of property located on a final, state approved and recorded plat; or a building site approved by a municipality and on a municipal sewerage system or having an approved “State and County Permit Application for Private Domestic Sewerage Systems.”

G. All gas main extensions with estimated main costs, including all Special Facilities Charges except Winter Construction Charges, exceeding $10,000 shall be reviewed by the Company for economic considerations. Gas service may be refused by the Company provided that the reasons and supporting analysis for such refusal are furnished to the customer and the Commission in writing. The customer shall be informed of their right to ask Commission Staff to review the refusal. ~~Furthermore, all gas main extensions with gas main costs exceeding $10,000, including all Special Facilities Charges except Winter Construction Charges, where the gas main cost, including all Special Facilities Charges except Winter Construction Charges, is greater than 150% of the allowance from Section 2.B. shall be charged a 32% tax gross-up on the required customer payment for gas main, exclusive of Winter Construction Charges. This tax gross-up is refundable during the Development Period.~~ D D D D D D D D

Continued to Sheet No. G11.03.

Wisconsin Public Service Corporation
Docket 6690-UR-123 2015 Test Year
Monitored Fuel Costs for 2015
Based on October 15, 2014 NYMEX

Month	Net kWh Produced	Monitored Fuel Cost	$/kWh	Cumulative $/kWh
January	1,207,922,233	$ 37,650,000	$ 0.03117	$ 0.03117
February	1,125,226,962	$ 32,573,000	$ 0.02895	$ 0.03010
March	1,149,419,896	$ 33,920,000	$ 0.02951	$ 0.02990
April	1,091,827,299	$ 32,633,000	$ 0.02989	$ 0.02990
May	1,116,964,425	$ 33,626,000	$ 0.03010	$ 0.02994
June	1,206,290,847	$ 36,823,000	$ 0.03053	$ 0.03004
July	1,282,712,737	$ 37,470,000	$ 0.02921	$ 0.02991
August	1,253,403,127	$ 37,570,000	$ 0.02997	$ 0.02992
September	1,152,395,868	$ 36,963,000	$ 0.03207	$ 0.03016
October	1,116,562,569	$ 36,822,000	$ 0.03298	$ 0.03042
November	1,114,844,514	$ 35,034,000	$ 0.03143	$ 0.03051
December	1,157,264,270	$ 34,302,000	$ 0.02964	$ 0.03044
Total	13,974,834,747	$ 425,386,000	$ 0.03044	

Wisconsin Public Service Corporation
Deferral Amortization Schedule

Deferral	PSCW Deferral Authorization	Notes	Amortization Period	Test Year Amount Electric	Test Year Amount Gas
DePere Energy Center Premium	6690-EB-104	4	2015-2023	2,280,420	0
Domestic Manufacturing Deduction and Research & Experimentation Tax Credits	6690-GF-115 6690-UR-119	4	2015	139,514	0
Domestic Manufacturing Deduction and Research & Experimentation Tax Credits	6690-GF-115 6690-UR-119	4	2015	94,426	0
Tax Deferrals	Precedent	3	2015	683,327	115,936
Tax Deferrals	Precedent	3	2015	(662,512)	(176,111)
Farm Re-Wiring Escrow	6690-UR-121	3	2015-2016	1,000,000	0
Conservation Escrow (pre-Act 141)	Various	3	2015-2016	1,850,433	726,956
Conservation Escrow (Act 141)	Various	1	2015-2016	14,055,509	4,005,361
Conservation Escrow Amortization Adjustment	Various	3	2015-2016	625,774	(1,644,205)
WI Revenue Stabilization Mechanism (RSM)	6690-UR-119	1	2015	(4,297,981)	(8,019,219)
Manufactured Gas Plant Cleanup	6690-UR-110	2	2015-2017	0	4,047,236
DSI Pre-certification-Edgewater	6690-GF-118	4	2015-2016	234,936	0
DSI Pre-construction-Edgewater	6690-GF-118	4	2015-2016	17,988	0
Production Tax Credits (Shift to Grants)	6690-UR-121	3	2015-2039	800,093	0
Glenmore Wind Asset Retirement	6690 (1/10/13 Accounting letter n PSC Ref #178828)	4	2015-2016	54,084	0
Crane Creek - Depreciation Deferral	6690-UR-122	4	2015-2039	(337,908)	0
Fox Energy Center - Purchased Power Contract Buyout	6690-EB-105	4	2015-2022	5,340,528	0
Fox Energy Center - Deferred Revenue Requirement	6690-EB-105	1	2015-2018	3,796,786	0
Fox Energy Center - Utility Acquisition Adjustment	6690-EB-105	3	2015-2038	1,790,574	0
Fox Energy Center - Contract Service Agreement	6690-EB-105	3	2015-2020	2,195,364	0
EPA Notice of Violation-Pulliam & Weston	6690-GF-126	4	2015-2016	477,072	0
EPA Notice of Violation-Columbia & Edgewater	6690-GF-126	4	2015-2016	484,020	0
Totals				$ 30,622,447	$ (944,046)

(1) Amount applies to Wisconsin Retail customers only.
(2) Amount allocated between Wisconsin and Michigan Retail customers.
(3) Amount allocated between all WPSC jurisdictions. (WI, MI, FERC)
(4) Amount allocated between Wisconsin Retail and FERC Market Based customers.
(5) Amount applies to FERC Market Based Rate customers only.

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates — 6690-UR-123

CONCURRENCE AND DISSENT OF COMMISSIONER ERIC CALLISTO

While I largely concur with the agreed upon revenue requirement, I dissent from the Final Decision on several issues: return on common equity; fixed customer charge increases; whether to open up a generic investigation on distributed generation and related rate design issues; an avoided transmission cost credit for distributed generation customers; electric revenue allocation; and overall rate design. I write separately here to explain my dissenting positions.

Return on Common Equity

I dissent from the 10.20 percent return on equity (ROE) set by the Commission. My first preference was to support that ROE, contingent upon no change in the fixed customer charges and the opening up of a generic investigation on distributed generation and related rate design issues. Recognizing that there was a desire to increase the fixed customer charge, my second choice was to support a reduced ROE of 10.00 provided that the fixed charges increased by no more than the Commission staff suggested 20 percent and the generic investigation was opened. Neither of those two options garnered a second vote. I note that in recent years I have voted in favor of modest increases in fixed customer charges, while not making a concomitant suggestion of a reduction in ROE. I have rethought that position, particularly in light of Wisconsin Public Service Corporation's (WPSC) request to increase its fixed charges by such a large amount.

We know that ROEs are set in part based on the financial risk profile of a utility. WPSC witness Mr. Moul testified that utility ROEs must "be commensurate with the risk to which the

Company's capital is exposed," and that this "proposed rate of return is commensurate with returns available on investments having corresponding risks."[1] We also know that increasing fixed customer charges reduces a utility's financial risk. WPSC witness Ms. Ferguson identified "reducing the volatility in [the utility's] revenues" as a principal reason for increasing fixed customer charges.[2] The Commission's Final Decision similarly acknowledges how WPSC's proposed fixed charge increase "shift[s] $114 million of variable revenue to fixed revenue," further noting Commission staff's observation "that the reduced revenue volatility supported a reduction in the authorized return on equity."[3] That there is a direct relationship between increasing fixed charges and financial risk reduction is not in question.[4]

Record evidence supports a ROE of 10.00, regardless of the impact of a fixed customer charge increase. Commission staff witness Ms. Hubert's Discounted Cash Flow (DCF) and Risk Premium analyses both support ROEs of below 10.00, and in the case of her two-stage DCF model, well below 10.00. The suggestion that the record does not support an ROE of below 10.20 is without support and directly contradicts the recommendations of Ms. Hubert.

Fixed Customer Charges and Generic Investigation on Rate Design

I disagree with the Commission's decision to increase fixed customer charges on WPSC's residential and small commercial electric and gas customers. I disagree as a matter of rate-making policy. I disagree as a matter of fundamental fairness. And I disagree as a matter of administrative process. The Commission is blazing new trail here, and it is doing so over the

[1] *See* Direct-WPSC-Moul-4.
[2] *See* Direct-WPSC-Ferguson-7.
[3] *See Final Decision* in this docket at page 32.
[4] It appears that the Commission may not understand this: "It is important to first understand what effect, if any, fixed charges have on a company's earnings, and sales and other risk factors before the Commission, as a matter of policy, determines it is appropriate to reduce return on equity as a matter of course when fixed charges increase." *See id.* at page 33.

well-reasoned objections of its own Commission technical staff. Issues this important, this divisive, and this impactful for customers, deserve more comprehensive investigation and should be dealt with as part of a statewide effort.

The ordered fixed customer charge increases are steep. For electric residential and small commercial customers, fixed charges will immediately go up between 83 percent and 126 percent.[5] For gas customers, the fixed charge increase is as much as 66 percent.[6] These increases will hit low and below average use customers the hardest. They will discourage the adoption of customer-sited, distributed generation. They will undermine the economics of energy efficiency and conservation. And they will restrict how much control customers have over how much they pay, making it harder for customers to pay less by using less.

All of this is justified in the name of "fairness" – and because of the supposedly urgent need to better "align" charges with costs, to eliminate customer confusion, and to ensure revenue stability for the utility. The rationale – for WPSC and this Commission – is that allowing the recovery of a certain amount of fixed or demand-related costs in a variable energy charge is inefficient and unfair to certain customers, particularly those who use more energy and who do not generate their own electricity. It is also a situation that WPSC argues presents a financial risk to the utility, to the extent that actual sales do not live up to forecasted expectations.

I have acknowledged the theoretical appeal underlying WPSC's proposal. As utility regulators, part of our job is aligning cost assignment with cost causation. We try to eliminate or lessen clear subsidies that are hidden in utility rate designs. And I believe that promoting

[5] The dollar increase is from $10.40 to $19.00 per month for residential customers, from $12.50 to $25.00 per month for single phase small commercial customers, and from $17.70 to $40.00 per month for three phase small commercial customers. *See Final Decision* in this docket at page 55.
[6] The dollar increase is from $10.25 to $17.00 per month for residential and standard volume commercial gas customers, from $135.00 to $150.00 per month for medium commercial customers, and from $595.00 to $620.00 for large commercial customers. *See Final Decision* in this docket at page 62.

efficient, reasoned, and fair price design is one of the most important functions of utility regulators and has been for the last 40 years, since the principles of long-run marginal cost pricing in utility rate design were first pioneered by the Wisconsin Commission.[7] But WPSC's case for, and the Commission's adoption of, dramatically increased fixed customer charges is premised on problems that do not exist.

The Commission's Final Decision talks an awful lot about subsidies, resulting both from low-usage customers not covering their share of fixed costs and from customers who generate their own electricity under a distributed generation tariff. Intra-class subsidization "is a product of the average embedded cost ratemaking approach that has been the long standing practice of this Commission,"[8] and which is consistent with a rate design that takes into account the long-run variability of utility system costs. That low usage customers pay less is a reflection, and an intended feature, of a regulatory framework that recognizes those customers as contributing to a lower cost utility system over the long run. As for customers generating their own energy, the supposed subsidy appears to be limited to just 119 customers who, according to the utility's own testimony, each come up about $800 short, per year, in terms of unrecovered costs. This is in the context of an annual electric revenue requirement of $1 billion. It is practically imperceptible.

The idea that current rate structures confuse customers who implement energy efficiency measures is without support. Ms. Ferguson conceded that WPSC neither has any empirical evidence nor has it done any analysis to support that claim.[9] And the Commission appears to

---

[7] *See Application of Madison Gas and Electric Co. for Authority to Increase its Electric and Gas Rates*, 2-U-7423, 59 WIS PSC 70, 75 (August 8, 1974) ("We believe that the appropriate benchmark for the design of electric rates in this case is marginal cost as represented by the practical variant, long-run incremental cost. If electric rates are designed to promote an efficient allocation of resources, this is a logical starting point.")
[8] *See* Direct-PSC-Singletary-26.
[9] *See Hearing Tr.* 59:13-14.

have recognized the weakness of this particular argument and did not include it as part of the Final Decision's rationale.

As for revenue volatility and financial risk, I believe they have to be viewed in the context of a regulatory jurisdiction that has full rate cases at least every other year and often annually, forward looking test years, pre-construction approvals, use of deferral accounting, fuel adjustment rules, and supportive returns on common equity. WPSC residential sales from 2011 through 2013 exceeded company forecasts. There is no suggestion that WPSC is not, on the whole, recovering its fixed costs, and there is no reason to expect that it will not continue to do in the coming years.[10] Indeed, if that were not the case, I cannot imagine a more supportive regulatory environment in which to address that problem, should it ever arise.

There is a peculiar hypocrisy to the Commission's rationale on fixed charge increases. It begins by trumpeting the specialized knowledge and technical competence of the Commission:

> In this proceeding, WPSC is asking the Commission to more strongly align fixed charges with fixed costs and, to fundamentally, engage in an exercise to enact reforms in rate design and re-structuring. Such an exercise goes to the core reason why Wisconsin created this Commission: to bring to bear this agency's expertise and knowledge about rates, how they are designed, and the kind of price signals to be sent to customers, and the sort of behavior this Commission wants to incent as a matter of sound public policy . . . To the extent that setting rates requires the weighing of evidence, the Commission must use its special experience, technical competence and specialized knowledge to identify a reasonable result, bearing in mind the various public policies that may be impacted by various rate making decisions.[11]

Our agency's "technical competence and specialized knowledge" is an odd thing for the Commission to rely on in a decision that plainly ignores the recommendations of Commission

[10] *See* Direct-WPSC-Ferguson-11-12 (noting how a WPSC residential customer with average usage covers his or her fixed costs).
[11] *See FinalDecision* in this docket at page 41.

technical staff regarding rate design, efficient price signals, and what sound public policy is in the context of this rate proceeding.

The reality is that the "technical competence and specialized knowledge" of this Commission advised *against* endorsing WPSC's proposed fixed customer charge increases. Two Commission staff witnesses, a Senior Rate Engineer and an Energy Policy Analyst, offered testimony on the fixed customer charge proposal. Their recommendations were not adopted by the Commission. Commission staff witness Mr. Albrecht stated the following:

> I chose a much smaller increase than the 140 or 180 percent increases WPSC proposed for the residential and small commercial customers, respectively, so as to have a lower impact on the small-usage customers . . . My alternative rate design also mitigates the range of intra-class bill impacts compared to WPSC's proposed high increases in demand and customer charges.[12]

Mr. Albrecht went on to explain his reasoning:

> First, there were recent Commission decisions where 40 percent utility-proposed customer charge increases were limited to 20 percent . . . All of these recent decisions have provided guidelines for Commission staff to follow in smaller utility electric rate cases and for this year's cases for the large utilities. Secondly, I agree with Commission staff witness Corey Singletary that the appropriate upper limit for the appropriate costs that should be included in the customer charges is less than the $25 level that WPSC proposed for the 2015 residential customer charges.[13]

Mr. Albrecht's proposed electric rate design included customer charge increases of 20 percent for residential customers (from $10.40 to $12.50) and small commercial customers (from $12.50 to $15.00 for single phase, and from $17.70 to $21.25 for three phase). His proposed gas increases were about 22 percent for small gas customers. The Commission instead is ordering increases of between 83 percent and 126 percent on the electric side, and as much as 66 percent on the gas side.

[12] *See* Direct-PSC-Albrecht-8.
[13] *See id.* at 9.

Commission staff witness Mr. Singletary also submitted testimony regarding the fixed customer charge issue. Mr. Singletary specifically addressed WPSC's arguments regarding the need for more revenue stability and financial risk mitigation:

> When one considers the fact that Wisconsin utilities receive the benefit of a number of risk mitigation measures, including forward looking test years, opportunities for biennial (if not annual) base rate cases, cost of fuel adjustments, and a variety of escrow treatments, this trend in sales hardly seems to present a great deal of risk to the utility's ability to recover its costs while still having a reasonable opportunity to return on its investments. In fact, assuming test-year sales forecasts are, on average, reasonably accurate, WPSC is really only exposed to sales risk in the second year the utility is out between cases. This of course assumes that the utility does not come in each year.[14]

In addition, Mr. Singletary conducted his own cost analysis, concluding that the company's fixed electric customer costs are substantially less than what the company had suggested. He explained:

> In order to arrive at a fixed cost analysis more inclusive than a bare-bones approach, I modified the utility's functionalized cost analyses so as to remove primary-voltage distribution costs that are classified as customer-varying costs. I believe that this is a reasonable method for determining a minimum cost contribution level as it includes all of the distribution costs most proximal to the end use customer – costs one would reasonably expect to vary by customer. This includes distribution costs extending from the meter, up through the service drop back up through the secondary distribution system, including any line transformers. In addition to distribution costs this method also includes all other customer classified costs included in the utility's functionalized analysis, including administrative and general costs. As this cost analysis is meant to inform rate design, I do not believe it is appropriate to include primary-voltage distribution-system costs as it is hard to contemplate a scenario where primary system costs would be significantly affected by the addition or subtraction of residential or small commercial customers on WPSC's system.[15]

---

[14] *See* Direct-PSC-Singletary-19-20.
[15] *See* Direct-PSC-Singletary-22.

Mr. Singletary's cost analysis suggested fixed cost levels of no more than $15.77 per residential customer, and no more than $18.34 per small commercial customer, for electric customers.[16] Again, the Commission is ordering a $19.00 fixed charge for residential customers, and between $25.00 and $40.00 for small commercial customers.

Commission staff also directly addressed the suggestion that "essentially all costs except for fuel are fixed costs."[17] Commission staff disagreed, with Mr. Singletary concluding:

> While I can appreciate how, from an accounting perspective, all of these costs are fixed in the sense that they do not vary from year to year, I do not believe it is appropriate to consider them as fixed costs for rate design purposes.[18]

Mr. Singletary further elaborated on the impact that increasing fixed customer charges will have on price signals, noting how "[a]s a monopoly essential service, customers have no way to respond to the price signal of a higher fixed charge."[19] He went on to explain:

> Perhaps more importantly though, the utility's view of price signals does not consider the fact that increasing the fixed charges will mute the price/revenue signal to the utility, diminishing the utility's incentive to respond to customer usage. This presents the future hazard of a utility that does not efficiently respond to changes in customer demand so as to manage its energy generation and supply portfolio in the most efficient way possible. The utility's one-way view of price signals and incentives ignores the fact that in a competitive market the supplier of the commodity must respond to the customer's needs, not vice versa. If the role of regulatory ratemaking is to serve as a proxy for a competitive market then I believe it is appropriate to consider the need for efficient price signals as a two-way street.[20]

In contrast, the Commission's Final Decision concludes that increasing the fixed customer charge for electric customers by between 83 percent and 126 percent will "encourage[] efficient

---

[16] I note the contrast between the conclusions of Mr. Singletary on this point and the Commission's suggestion that "evidence in the record established that WPSC's fixed costs far exceeded the proposal to raise its customer charge." *See Final Decision* in this docket at page 44.
[17] *See* Direct-PSC Singletary-23.
[18] *See id.* at 24.
[19] *See id*.
[20] *See id.* at 26.

utility scale planning."[21] However, nowhere in the Final Decision is it explained how muting customer price signals will accomplish such an objective.

And regarding how the fixed customer charge increase would specifically affect energy efficiency and conservation, Mr. Singletary concluded:

> It is sufficient to say that I disagree with the utility's general belief that such a rate design shift will have limited effect on energy efficiency and conservation. However, I have particular concerns in this area given the fact that the utility has not presented any indication of what it believes is an appropriate level for fixed charges in the long term, only indicating that the charges they have proposed are between the current rates and what the utility could conceivably justify based on their views regarding cost-of-service. Simply put, I am concerned that the fixed charges proposed in this proceeding are but a way station on the path to some higher, unspecified level.[22]

Indeed, no party to this proceeding claimed that WPSC's proposed fixed customer charge will not negatively impact energy efficiency and conservation.[23] Even WPSC witness Ms. Ferguson acknowledged how the proposal would likely result in a "slight decrease" in the cost-effectiveness of energy efficiency and conservation efforts.[24]

I agree that we should rely on the specialized expertise of this agency. But let's be honest about what that expertise advises. The recommendations and analytical conclusions

---

[21] *See Final Decision* in this docket at 45.
[22] *See* Direct-PSC-Singletary-25.
[23] The positions of CUB, RENEW Wisconsin, and ELPC are all consistent with Mr. Singletary's, with respect to the impact of WPSC's proposal on energy efficiency and conservation. *See* Direct-CUB-Wallach-35 ("Such a shift would distort price signals, frustrate investments in energy efficiency and distributed resources, and inequitably burden smaller customers."); RENEW Wisconsin Initial Brief at page 4 (observing how the proposal "ensures immediate harm to energy efficiency"); ELPC Initial Brief at page 2 (noting that the fixed charge increase "discourages energy efficiency"). I also note for illustrative purposes that the Program Administrator responsible for running Wisconsin's Focus on Energy program, our statewide energy efficiency and renewable resource program, has cautioned Commission staff that the implications of substantially increasing fixed customer charges "are profound," that doing so "would require Focus on Energy incentives to increase in order to sustain participation," and that such rate design changes would increase "the cost per delivered unit of energy savings" and ultimately decrease the achievable energy savings. *See Memorandum* from Focus on Energy staff Chad Bulman and Tamara Sondgeroth, to Commission staff Carol Stemrich, Jolene Sheil, Preston Schutt, and Joe Fontaine, dated October 9, 2014, at pages 4-5. I understand that this memorandum is not part of the record in this proceeding, but it is relevant, and the Commission is free to take administrative notice of it under Wis. Stat. § 227.45(3) or reopen the administrative record and allow it into evidence.
[24] *See Hearing Tr.* 43:2-4.

which reflect Commission staff's "technical competence and specialized knowledge" about "rates, how they are designed, and the kind of price signals to be sent to customers, and the sort of behavior this Commission wants to incent as a matter of sound public policy,"[25] include the following:

- A fixed customer charge increase of no more than 20 percent for residential and small commercial customers;
- A functional cost of service analysis showing fixed electric costs of no more than $15.77 per residential customer, and no more than $18.34 per small commercial customer;
- A recognition that steep fixed customer charge increases unfairly impact low usage customers;
- An understanding of utility financial risk that is cognizant of the numerous risk mitigation features already present in Wisconsin's regulatory framework;
- A view of appropriate rate design which understands the difference between fixed costs from an accounting standpoint and the importance of designing fixed charges that are consistent with the long-run variable cost of providing utility service; and
- A recognition that steep fixed customer charge increases will negatively impact customer energy efficiency and conservation.

The Commission either ignored or disagreed with all of this. I agree with the idea that we exist as a regulatory body in part to "bring to bear" our agency's "expertise and knowledge." But there is no support in this Final Decision for the suggestion that is what the Commission is doing here. The Commission's decision is a near complete endorsement of WPSC's push to increase its fixed customer charges. And it is a decision that is reached in the face of plain and unequivocal opposition from Commission technical staff.

[25] *See Final Decision* in this docket at page 41.

The Commission's Final Decision on fixed charges has other problems. It "finds that it is not reasonable at this time to specify what specific costs are appropriate to consider when setting fixed charge rates,"[26] yet concludes "that the fixed customer charges should be increased to more closely reflect the utility's fixed costs to provide basic service to a customer."[27] It ignores record evidence showing that it is more likely that low income residents in WPSC's service territory are low usage customers, and thus those customers will be disproportionately harmed by the fixed charge increase.[28] It states that "a customer's contribution to system demand is not necessarily less because they are a low energy customer," despite uncontested evidence submitted by WPSC showing that most low use residential customers have lower than average demand.[29] It relies heavily on the existence of supposed "subsidies" in current rate design, yet never identifies the extent of these subsidies, nor attempts to quantify them in dollars or as a percentage of utility revenue. It also fails to coherently apply our Energy Priorities Law, Wis. Stat. §§ 196.025(1)(ar) and 1.12(4), to a rate-setting decision that will make energy efficiency, conservation, and renewable energy less cost-effective for WPSC's residential and small commercial customers. The Final Decision throws a lot at the wall, but very little of it holds up.

I agree that public utility regulation "is intended to simulate a free market process for monopoly utilities."[30] We are meant to stand in as a proxy for the free market – for competition – because where none exists, the consuming public is otherwise captive and without recourse in

[26] *See id*. at 38.
[27] *See id*. at 55.
[28] *See* Ex.-WPSC-Laursen-5; Tr. 132-141; CUB Reply Brief at pages 7-8.
[29] *See* Ex.-WPSC-Ferguson-3; Tr. 67:1-16.
[30] *See Final Decision* in this docket at page 43.

the face of a monopoly provider of essential utility service. Today's decision does not protect the consuming public or advance the public interest.

Here is what it does do. If you use less energy than an average user, you are going to pay more on your utility bill. The lower your use, the more you will pay, relative to the current bill structure. You will also have less control over how much you pay. Folks who live in the smallest dwellings – those in apartments, multi-unit housing, often individuals on fixed incomes, will be hit the hardest. Low usage customers are more likely to be low income customers. So the effect of increasing fixed customer charges will disproportionately impact low income populations. Today's decision will undermine the cost-effectiveness of energy efficiency and conservation measures and discourage the adoption of distributed generation technologies going forward.

It is time to take a measured look at the issues raised by the utility industry's nationwide push to "realign" rate structures. I think we should slow down, approve no fixed charge increase in this case, and open up a generic investigation. I would support a timeline that would ensure completion before the rate case season for test year 2017, and would involve a broad range of interested stakeholders and Commission staff. In addition to rate re-design and the specific issue of fixed charges, a more comprehensive investigation would evaluate placing a fair and transparent value on distributed generation, and at least start down the discussion path of the role of regulated utilities in a future with flat load growth, increased distributed generation and more robust consumer involvement in energy choices. Other states are way ahead of Wisconsin in this regard. The solution provided by WPSC here, and other regulated companies in this state, is not holistic, not forward thinking, and largely self-serving. It is our job – as regulators – to push and guide where that works, and to lead when others will not.

I would have kept the fixed customer charges where they are now, or limited the increases to 20 percent provided that such an increase would be accompanied by a 20 basis point reduction in ROE and the opening of a generic investigation as I have described.

Customer Owned Generation and Credit for Avoided Cost of Transmission

I disagree with the Commission's decision to not authorize an avoided transmission cost credit for Pg-2A and Pg-2B customers. As Commission staff witness Mr. Singletary testified, "[j]ust as a kWh of [distributed generation] supplied energy displaces a kWh of energy supplied from the grid, so does [distributed generation] supplied energy avoid the need for the transmission to move that displaced energy."[31] And that idea is consistent with this Commission's recent decision, in docket 5-UR-106, ordering an avoided transmission cost credit for distributed generation customers of Wisconsin Electric Power Company.[32]

Overall Electric and Gas Rate Design and Revenue Allocation

I would have supported Commission staff's proposed revenue allocation, which included a tighter range between the residential and small commercial customer classes, both of which are taking the brunt of the fixed customer charge increases in today's decision. The Commission staff proposed allocation would have kept the residential overall increase at about 2 percent while the small commercial class would have an increase of between 0.20 percent and 1.12 percent. The Commission opted for a higher residential increase (3.43 percent) and keeping the remainder of the small commercial customers at no increase at all. I would have preferred a

[31] *See* Direct-PSC-Singletary-28.

[32] *See Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC, both d/b/a We Energies, for Authority to Adjust Electric, Natural Gas, and Steam Rates*, docket 5-UR-106, Final Decision (PSC REF#: 178105), at pages 75-76 (December 21, 2012) ("The Commission finds it reasonable that the CGS8 avoided cost rate reflect average MISO LMP plus the utility's avoided cost of transmission.")

more modest impact on the residential customers, particularly in light of the steep fixed charge increases coming their way.

I similarly would have supported Commission staff's proposed overall rate design for both electric and gas customers, consistent with my earlier discussion regarding the fixed charge increases. I also preferred Commission staff's approach on the changes to the demand and energy charges for both the Cg-20 and Cp rate classes. Commission staff's proposed changes would have minimized intra-class disparities.

DL: 00951764

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates | 6690-UR-123

CONCURRENCE OF COMMISSIONER ELLEN NOWAK

I concur with the majority opinion and write in response to the dissent of Commissioner Callisto regarding the Commission's changes to WPSC's rate structure, and specifically the increase in fixed charges for the company's residential and small commercial customers. Commissioner Callisto disagrees with the majority on this issue as a matter of policy, requesting a more thorough investigation. He relies on the "long standing practice" of the Commission that results in low-usage customers paying less because they contribute to a lower cost utility system over the long run.[1]

The legislature has put the responsibility for maintaining a fair public policy in this area squarely in the hands of this Commission. "Long standing practice" is not a reason to avoid altering that public policy, particularly in this case where a majority of the uncharacteristically long record is dedicated to this particular issue. To say that the investigation was not thorough is incorrect and mischaracterizes this record.

Moreover, there is broad recognition that the utility industry is changing. Those changes include a stronger emphasis on energy efficiency, expanded distributed generation, and a shift in the role of the regulated utility in response to these changes. What has remained constant is the utility's obligation to provide reliable service to all customers, regardless of use and demand level.

[1] Dissent, at 4.

In this case, the Commission makes a public policy decision to move away from the "long standing practice" in order to proactively address these changes. The Commission accepted the plethora of evidence showing that low use is not the same as low demand, and therefore low-use customers do not necessarily contribute to a lower cost utility system.[2] There was also evidence to support that low-income customers are not necessarily low-use customers.[3] Taken together, the Commission correctly concluded that it is unfair to allow continued subsidization of low use customers through a rate structure consisting of misleadingly low fixed charges and high variable charges.

Commissioner Callisto also notes "a peculiar hypocrisy to the Commission's rationale."[4] He takes issue with the Commission's statement that one core reason for creating this Commission was to create a tribunal with a certain set of expertise and knowledge to determine sound public policy in an area of very complicated subject matter.[5] Commissioner Callisto interprets this statement as a commitment to agree with the Commission's technical staff on the subject of rate restructuring, and quotes Commission staff's testimony on the subject in great length.

Commissioner Callisto confuses the expertise of the tribunal with the technical expertise of the Commission staff. I agree that Commission staff is very knowledgeable about the technical aspects of the utility industry. Commission staff's role is not one of advocacy, but rather to present all of the available information. While they are free to, and do, make recommendations on both technical and policy issues, those suggestions should not necessarily

[2] Rebuttal-WPSC-Ferguson-5r-9r; WPSC Init. Br. 28.
[3] WPSC Init. Br. 29; Laursen, Tr. 186-188.
[4] Dissent, at 5.
[5] Dissent, at 5. Final Decision, at 41.

receive more weight from the Commission than recommendations from other parties that are also supported by evidence in the record.

In this record, Commission staff made a recommendation on what should be included in fixed charges.[6] The interveners also made recommendations. Ultimately, it was up to the Commissioners, with our experience and expertise, to determine which recommendation to accept. While I understand that Commission Callisto and the majority may disagree on the public policy incentives underlying ratemaking, I don't think that having an opinion that differs from that of Commission staff amounts to hypocritical rational.

Finally, I also note some irony in Commissioner Callisto's statement that the Commission ignored or disagreed with record evidence to support its conclusion. Commissioner Callisto is correct that the Commission did disagree with some of the record evidence, as it is the Commission's prerogative in weighing evidence. But at least the Commission considered all of the evidence in the record when making its conclusion and did not rely on evidence outside of the record, as Commissioner Callisto does, to reach his conclusion. It is worth noting that Commissioner Callisto's dissent cites a memorandum to Commission staff from the Focus on Energy administrator where the administrator opines on particular rate designs and energy efficiency.[7] This memorandum was neither submitted as evidence in the record nor did this Commission take administrative notice of the document. As a result, none of the parties had an opportunity to provide testimony or otherwise comment on the memorandum.

DL: 00951744

[6] Direct-PSC-Singletary-23.
[7] Dissent, at 9, footnote 23.