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PUBLIC SERVICE COMMISSION OF WISCONSIN

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 — 5-UR-107

FINAL DECISION

This is the Final Decision concerning the application of Wisconsin Electric Power Company (WEPCO) and Wisconsin Gas LLC (WG) (collectively We Energies) for authority to change electric, natural gas, and steam rates on January 1, 2015, and to change electric rates and WG natural gas rates on January 1, 2016.

<u>Final overall rate changes in 2015 are authorized consisting of a $11,235,000 annual rate decrease for WEPCO Wisconsin retail electric operations, a 0.39 percent decrease; a $10,660,000 annual rate decrease for WEPCO natural gas operations (WE-GO), a 2.39 percent decrease; a $481,000 annual rate increase for WEPCO's Valley Steam (VA Steam)[1] operations, a 2.02 percent increase; a $1,241,000 annual rate increase for WEPCO's Milwaukee County steam (MC Steam)[2] operations, a 7.25 percent increase; and a $17,097,000 annual rate increase for WG, a 2.63 percent increase, for the test year ending December 31, 2015, based on a 10.20 percent return on common equity for WEPCO and a 10.30 percent return on common equity for WG.</u>

<u>Additional overall rate changes in 2016 are authorized consisting of a $26,614,000 annual rate increase for WEPCO Wisconsin retail electric operations, a 0.92 percent increase; and a $21,400,000 annual rate increase for WG natural gas operations, a 3.21 percent increase; for the</u>

[1] Valley Steam operations are sometimes referred to as Downtown Milwaukee Steam (DMS) operations.
[2] Milwaukee County Steam operations are sometimes referred to as Wauwatosa Steam (WS) operations.

test year ending December 31, 2016. There is no additional 2016 rate change for WE-GO or the two steam utilities.

Introduction

On May, 30, 2014, We Energies requested Wisconsin jurisdictional revenue increases of $55.4 million (1.91 percent) in 2015 and $29.8 million (1.01 percent) in 2016 for its electric operations; a $10.7 million (2.39 percent) revenue decrease for its natural gas operations (WE-GO) in 2015; a $0.5 million (2.10 percent) revenue increase in 2015 for its VA steam operations; and a $0.8 million (4.56 percent) revenue increase in 2015 for its MC Steam operations. WG requested increases of $21.1 million (3.27 percent) in 2015 and $21.4 million (3.21 percent) in 2016 for its natural gas operations.

Prior to the application, We Energies initiated discussions with Citizens Utility Board (CUB), Wisconsin Industrial Energy Group (WIEG), Wisconsin Paper Council (WPC) (collectively, the Settlement Parties), and Commission staff regarding the possibility of limiting the number of contested issues in its rate application. Before these discussions, Commission staff began a review in early April 2014 of working papers and other records supporting We Energies' forecasted test-year revenue shortfalls or surpluses that it indicated would have been sought in a fully-litigated rate case proceeding. As a result of Commission staff's review and proposed non-fuel adjustments, and discussions among the Settlement Parties, a settlement agreement was reached on the majority of revenue requirement issues for the 2015 and 2016 test years.

The test-year 2015 adjustments that We Energies and the Settlement Parties agreed to amount to a $82,618,000 reduction to Wisconsin retail jurisdiction electric revenue requirement, an $8,161,000 reduction to WE-GO natural gas revenue requirement, a $763,000 reduction to VA Steam revenue requirement, a $621,000 reduction to MC Steam revenue requirement, and a $15,313,000 reduction to WG revenue requirement. We Energies then used the resulting deficiencies and surpluses after the settlement adjustments as the starting point for its filed rate change requests. The settlement agreement includes a 2016 step increase in electric rates of $26.614 million for fall-off of fuel and Treasury Grant credits and elimination of a Cross-State Air Pollution Rule (CSAPR) amortization that ends at the end of 2015, as well as a 2016 step increase in WG rates of $21.4 million for the West Central Lateral project and the pension credit amortization fall-off. Issues not included in the settlement agreement include fuel costs, annual payments to the Fund for Lake Michigan, costs for a solar project, treatment of System Support Resource (SSR) charges and revenues, and all cost of service and rate design issues.

On June 27, 2014, a prehearing conference was held to determine the issues to be addressed in this docket and to establish a schedule for the hearings. Hearings were held on September 24, 2014, in Madison to receive technical information, and on October 8, 2014, in Milwaukee to receive public comments into the record. The Commission received approximately 2,000 comments from members of the public as part of the Commission's public hearing process that involved the opportunity to submit written comments through the Commission's website, or at the public hearing, or to testify at the public hearing.

The Commission considered this matter at its open meeting of November 14, 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. Presently authorized rates for WEPCO's Wisconsin retail electric utility operations will produce operating revenues of $3,266,825,000 for the test year ending December 31, 2015, which results in a net operating income of $376,504,000 and an annual revenue excess of $11,235,000.

2. Presently authorized rates for WE-GO will produce operating revenues of $447,593,000 for the test year ending December 31, 2015, which results in a net operating income of $43,836,000 and an annual revenue excess of $10,660,000.

3. Presently authorized rates for WEPCO's VA Steam utility operations will produce operating revenues of $23,828,000 for the test year ending December 31, 2015, which results in a net operating income of $2,107,000 and an annual revenue deficiency of $481,000.

4. Presently authorized rates for WEPCO's MC Steam utility operations will produce operating revenues of $17,123,000 for the test year ending December 31, 2015, which results in a net operating income of $1,174,000 and an annual revenue deficiency of $1,241,000.

5. Presently authorized electric and natural gas rates of WEPCO are unreasonable because they produce excess electric and natural gas revenues.

6. Presently authorized steam rates of WEPCO are unreasonable because they produce inadequate steam revenues.

7. Presently authorized rates for WG's natural gas utility operations will produce operating revenues of $653,422,000 for the test year ending December 31, 2015, which results in a net operating income of $63,060,000 and an annual revenue deficiency of $17,097,000.

8. Presently authorized natural gas rates of WG are unreasonable because they produce inadequate natural gas revenues.

9. For the WEPCO Wisconsin retail electric utility, the estimated rate of return on average net investment rate base of $4,432,940,000 at current rates subject to the Commission's jurisdiction for the test year is 8.49 percent, prior to the application of certain credits, which is inadequate. After inclusion of certain credits, the estimated net income at present rates is excessive.

10. For WE-GO, the estimated rate of return on average net investment rate base of $435,187,000 at current rates subject to the Commission's jurisdiction for the test year is 10.07 percent, which is excessive.

11. For the WEPCO VA Steam utility operations, the estimated rate of return on average net investment rate base of $28,097,000 at current rates subject to the Commission's jurisdiction for the test year is 7.50 percent, which is inadequate.

12. For the WEPCO MC Steam utility operations, the estimated rate of return on average net investment rate base of $22,523,000 at current rates subject to the Commission's jurisdiction for the test year is 5.21 percent, which is inadequate.

13. For WG, the estimated rate of return on average net investment rate base of $875,941,000 at current rates subject to the Commission's jurisdiction for the test year is 7.20 percent, which is inadequate.

14. A reasonable increase in operating revenue for the test year to produce an 8.60 percent return on WEPCO's average net investment rate base for Wisconsin retail electric operations is $8,233,000, prior to the application of certain credits. After inclusion of certain

credits, a decrease in operating revenues of $11,235,000 is reasonable to produce an 8.60 percent return on WEPCO's average net investment rate base for Wisconsin retail electric operations.

15. A reasonable decrease in operating revenue for the test year to produce an 8.60 percent return on WE-GO's average net investment rate base is $10,660,000.

16. A reasonable increase in operating revenue for the test year to produce an 8.52 percent return on WEPCO's average net investment rate base for VA Steam utility operations is $481,000.

17. A reasonable increase in operating revenue for the test year to produce an 8.52 percent return on WEPCO's average net investment rate base for MC Steam utility operations is $1,241,000.

18. A reasonable increase in operating revenue for the test year to produce an 8.36 percent return on WG's average net investment rate base for natural gas operations is $17,097,000.

19. WEPCO's and WG's filed operating income statements and net investment rate bases for the test year, as adjusted for Commission decisions, are reasonable.

20. It is reasonable to accept the revenue requirement adjustments included in the settlement agreement between We Energies and the Settlement Parties.

21. A reasonable estimate of annual escrowed uncollectible accounts expense for WEPCO's electric utility is $29,517,000, which is comprised of $26,504,000 of estimated net write-offs plus $3,013,000 of amortization expense on a Wisconsin retail basis.

22. A reasonable estimate of annual escrowed uncollectible accounts expense for WE-GO is $1,272,000, which is comprised of $3,172,000 of estimated net write-offs less a negative amortization expense of $1,900,000.

23. A reasonable estimate of annual escrowed uncollectible accounts expense for WG is $5,895,000, which is comprised of $16,655,000 of estimated net write-offs less a negative amortization expense of $10,760,000.

24. A reasonable estimate of annual escrowed Agriculture Service Program expense to be recorded for WEPCO electric operations is $1,317,000.

25. A reasonable estimate of annual escrowed conservation expense to be recorded for WEPCO electric operations is $57,903,000, which is comprised of $46,604,000 of estimated expenditures plus $11,299,000 of amortization of overspent amounts.

26. A reasonable estimate of annual escrowed conservation expense to be recorded for WE-GO is $7,883,000, which is comprised of $8,054,000 of estimated expenditures less a negative amortization of $171,000 of amortization of underspent amounts.

27. A reasonable estimate of annual escrowed conservation expense to be recorded for WG is $10,323,000, which is comprised of $10,692,000 of estimated expenditures less a negative amortization of $369,000 of amortization of underspent amounts.

28. Unless discussed separately in this Final Decision, it is reasonable for We Energies to record the annual expense amounts itemized in Ex.-WEPCO/WG-Ackerman-4, Schedule 1, for all items listed for 2015 and 2016 or until the Commission authorizes a different amortization expense to be recorded.

29. It is reasonable to forecast that WEPCO will burn a blend of 60 percent bituminous coal and 40 percent Powder River Basin (PRB) coal for both units at the Elm Road Generating Station (ERGS) during 2015.

30. It is reasonable to forecast that WEPCO will have an additional one and one-half-week inspection outage at each ERGS unit during 2015.

31. It is reasonable to increase 2015 non-monitored fuel forecasts by $3.6 million to reflect a forecast for interstate pipeline capacity costs for the Valley Power Plant and testing costs for Valley Unit 2 after its conversion to natural gas during 2015.

32. It is reasonable to increase 2015 monitored fuel forecasts by $1.7 million to reflect a revision of WEPCO's modeling assumptions for auxiliary load at its power plants.

33. It is reasonable to waive Order Point 34 in the Final Decision in docket 5-UR-106 during 2015 for each ERGS unit while that unit is test-burning PRB coal blends.

34. It is reasonable to accept and incorporate Commission staff's uncontested adjustments to WEPCO's filed 2015 fuel costs and the uncontested fuel adjustments for coal contracts executed since Commission staff's fuel plan audit.

35. It is reasonable in this proceeding to forecast 2015 fuel costs based on the New York Mercantile Exchange (NYMEX) futures settlement prices for natural gas, heating and crude oil prices as of October 15, 2014.

36. It is reasonable to reflect the updated NYMEX futures settlement prices impacts on the Midcontinent Independent System Operator, Inc. (MISO) locational marginal prices (LMP) to revise the Real Time Market Pricing (RTMP) revenues.

37. A forecasted 2015 total company fuel cost of $1,011.061 million is reasonable.

38. It is reasonable to set a 2015 fuel cost plan-year cost of monitored fuel at $815.911 million, or $30.98 per megawatt-hour (MWh), as shown in Appendix F.

39. It is reasonable to monitor all fuel costs using an annual bandwidth of plus or minus 2 percent.

40. It is not necessary to make a determination at this time whether SSR costs should be considered a monitored fuel cost or transmission-related cost.

41. It is reasonable that the estimated additional payments of $41.9 million received from MISO for the Presque Isle Power Plant (PIPP) Retirement SSR agreement should be included in WEPCO's 2015 electric revenue requirement, in addition to the estimated $48.8 million included in the settlement between We Energies and the Settlement Parties, for a total Wisconsin retail amount of $90.7 million revenue included in WEPCO's 2015 electric revenue requirement, with actual revenues escrowed for resolution in a future proceeding.

42. It is reasonable for WEPCO to utilize escrow accounting treatment for the 2015 PIPP SSR revenue payments from MISO and that carrying costs on the escrow balance shall accrue at WEPCO's authorized weighted cost of capital.

43. It is reasonable that the PIPP SSR revenue received by WEPCO in 2014 not be deferred or given escrow accounting treatment.

44. It is reasonable to continue to review the appropriateness of whether or not to include recovery in rates of the costs associated with the Wisconsin Pollutant Discharge Elimination System (WPDES) Settlement Agreement on a case-by-case basis. It is further reasonable to include $3.1 million in both the 2015 and the 2016 electric revenue requirement

reflecting WEPCO's annual contribution to the Fund for Lake Michigan and to exclude the solar project costs from the 2016 electric revenue requirement.

45. It is reasonable to include sales revenue of $4.0 million in the WG 2015 test-year revenue requirement to reflect additional sales associated with the conversion of the Valley Power Plant to natural gas.

46. It is reasonable to continue escrow accounting treatment of the Treasury Grant credits and to require WEPCO to inform the Commission of any changes in the Treasury Grant credits on an annual basis until such time that the credits are final.

47. It is reasonable to continue escrow accounting treatment of the Section 199 Domestic Production Tax Deduction.

48. It is reasonable to authorize escrow accounting treatment of WEPCO's Agriculture Service Program.

49. It is reasonable to calculate the revenue requirement using the depreciation rates authorized in docket 5-DU-102.

50. A long-term range of 48.5 percent to 53.5 percent for WEPCO's common equity ratio, on a financial basis, is reasonable and provides adequate financial flexibility.

51. A long-term range of 47.0 percent to 52.0 percent for WG's common equity ratio, on a financial basis, is reasonable and provides adequate financial flexibility.

52. An appropriate target level for WEPCO's test-year average common equity measured on a financial basis is 51.0 percent.

53. An appropriate target level for WG's test-year average common equity measured on a financial basis is 49.5 percent.

54. A reasonable estimate of the debt equivalent of WEPCO's off-balance sheet obligations to be imputed into the financial capital structure for the test year is $363,583,000.

55. A reasonable financial capital structure for WEPCO for the test year consists of 51.00 percent common equity, 0.44 percent preferred stock, 39.14 percent long-term debt, 4.16 percent short-term debt, and 5.26 percent debt equivalent of off-balance sheet obligations.

56. A reasonable financial capital structure for WG for the test year consists of 49.50 percent common equity, 32.74 percent long-term debt, and 17.76 percent short-term debt.

57. It is reasonable that WEPCO's and WG's dividend restrictions be based on the financial capital structure in this proceeding.

58. It is reasonable to require WEPCO and WG to submit ten-year financial forecasts in their next rate proceeding.

59. It is reasonable to require WEPCO 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.

60. A reasonable utility capital structure for ratemaking for WEPCO for the test year consists of 51.90 percent common equity, 0.48 percent preferred stock, 43.04 percent long-term debt, and 4.58 percent short-term debt.

61. A reasonable utility capital structure for ratemaking for WG for the test year consists of 48.91 percent common equity, 33.13 percent long-term debt, and 17.96 percent short-term debt.

62. A reasonable interest rate for WEPCO's and WG's short-term borrowing through commercial paper is 0.60 percent for the test year.

63. A reasonable average embedded cost for WEPCO's long-term debt is 4.80 percent for the test year.

64. A reasonable average embedded cost for WG's long-term debt is 5.37 percent for the test year.

65. A reasonable average cost for WEPCO's preferred stock is 3.95 percent for the test year.

66. The rate of return on utility common stock equity of 10.2 percent for WEPCO, included in the settlement between We Energies and the Settlement Parties, is reasonable for the test year.

67. The rate of return on utility common stock equity of 10.3 percent for WG, included in the settlement between We Energies and the Settlement Parties, is reasonable for the test year.

68. A reasonable weighted average composite cost of capital is 7.40 percent for WEPCO.

69. A reasonable weighted average composite cost of capital is 6.92 percent for WG.

70. It is reasonable to continue to rely on the results of a number of electric cost-of-service studies (COSS) along with other factors, such as bill impacts, when allocating revenue responsibility among the various customer classes.

71. It is reasonable to approve rates for electric service for the test year to achieve customer class changes in revenue as shown in Appendix B.

72. It is reasonable to consider the results of all COSS in the record for the purpose of assigning class revenue requirement responsibility.

73. It is not reasonable at this time to identify specific costs for inclusion in fixed charges.

74. It is reasonable to consider the setting of fixed charges as a policy decision, and to consider state and Commission policies, fairness, and economic efficiency over the short and long term when setting fixed charge rates for residential and small commercial customers.

75. The rate factors and methodology proposed by Commission staff for implementing 2005 Wisconsin Act 141 (Act 141) are reasonable, and it is reasonable to require WEPCO to adopt the accounting treatment of Act 141 revenue with respect to the large energy customers similar to that used by the other investor-owned utilities.

76. The increase to fixed facilities charges proposed by WEPCO is reasonable.

77. It is reasonable to require WEPCO to examine in its next base rate case whether the facilities charge for single and three-phase customers should be different.

78. An extra meter charge of $1.81 per month for small customer classes and $5.23 per month for medium and large customer classes is reasonable.

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

80. It is reasonable to create a new St2 tariff based on the proposal by the city of Milwaukee that is shown in exhibit Ex.-COM-Shambarger-1.

81. It is not reasonable to accept Charter Steel's (Charter) proposal for a new tariff for customers served directly from a high-voltage transmission system.

82. It is reasonable to discontinue the Rg2 and Cg6 Level 2 rate options and the Rg3 tariff and switch existing customers to the Rg2 or Cg6 Level 1 rates effective January 1, 2015.

83. It is reasonable to increase the demand charges for customer classes subject to such charges.

84. It is reasonable to approve the changes to the electric extension embedded allowances, and the numerous other minor tariff language changes to the electric service rules and regulations that are shown in exhibit Ex.-WEPCO/WG-Rogers-18.

85. It is reasonable to maintain the interruptible credits for the CpFN, Cg3, and Cp3 classes at the currently authorized amounts.

86. It is reasonable to extend the contracts of the existing RTMP customers by 36 months at the current baselines.

87. It is reasonable to allow Charter to enroll under the RTMP rider at the current Contract Services Tariff baselines.

88. It is reasonable that WEPCO work with WIEG, other interested stakeholders, and Commission staff to evaluate its electric cost of service with respect to the seasonality of its costs, and for WEPCO to develop and submit a seasonally-differentiated electric rate design proposal in its next base rate proceeding.

89. It is reasonable to approve the changes to the steam extension embedded allowances that are shown in exhibit Ex.-WEPCO/WG-Rogers-4 and 5.

90. WEPCO's proposal to close the CGS-1, CGS-2, CGS-6, CGS-7, and CGS-8 tariffs to new customers effective December 31, 2015, is reasonable.

91. It is reasonable to authorize WEPCO's proposal to allow existing CGS-1, CGS-2, CGS-6, and CGS-8 customers who applied for service under these tariffs as of October 7, 2014, to continue to take service under the terms of their current CGS tariff through December 31,

2024. Customers who have applied for service under any of these tariffs after October 7, 2014, will be transferred to the appropriate COGS tariff effective January 1, 2016.

92. WEPCO's proposed COGS-DS-FP, COGS-DS-VP, COGS-NM, and COGS-DS tariffs are reasonable.

93. It reasonable to require WEPCO to install meters capable of measuring the actual output capacity of generating systems enrolled under COGS-NM and COGS-NP on an interval basis. The cost of this metering shall be borne by WEPCO.

94. It is reasonable to require WEPCO to perform a true-up at the end of 2016 wherein the metered monthly maximum generation capacity of customers enrolled under COGS-NM or COGS-NP shall be compared to the rated nameplate capacity of the same system.

95. WEPCO's request to require that new distributed generation (DG) customers who take service under the new COGS tariffs own their generation equipment is not reasonable in the context of this rate case. It is reasonable to continue to evaluate whether third-party owned DG systems comply with Wisconsin statues and administrative rules on a case-by-case basis.

96. WEPCO's request for a waiver of Wis. Admin. Code § PSC 113.0406(5) to the new COGS-DS-FP, COGS-DS-VP, and COGS-NM tariffs is reasonable.

97. WEPCO's proposed Cg4 and Cp4 standby service tariffs are unreasonable.

98. It is reasonable to direct WEPCO to develop a standby rate proposal in close cooperation with any affected customers, and to present that rate proposal in WEPCO's next full rate proceeding.

99. It is reasonable to defer the revenue collected through the new COGS tariffs until WEPCO's next full rate proceeding.

100. It is not reasonable at this time to open a separate investigation, or direct that a stakeholder collaborative process be convened, in order to examine DG rate design issues.

101. It is reasonable to continue 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.

102. It is reasonable to authorize rates for natural gas service for WE-GO and WG as shown in Appendices D and E, respectively.

103. It is reasonable to treat each metered service as a separate account because the applicable service charges will better recover the investment and operating costs associated with each meter and service lateral than meter aggregation.

104. It is reasonable for WE-GO and WG to eliminate tariffs providing Natural Gas Vehicle (NGV) Sales Service and to provide such service pursuant to rates serving similar service rate classes.

105. Rely-A-Bill changes are reasonable.

Conclusions of Law

The Commission 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, 134, and 137 to issue a Final Decision authorizing WEPCO and WG to place in effect the rates and rules for electric, steam, and natural gas utility service set forth in Appendices B, C, D, and E, and the fuel cost treatment set forth in Appendix F, subject to the conditions specified in this Final Decision.

Opinion

We Energies and Business

WEPCO and WG are public utilities, as defined in Wis. Stat. § 196.01(5). WEPCO conducts its operations primarily in three operating segments: an electric utility segment, a natural gas utility segment, and a steam utility segment. WEPCO serves approximately 1,100,000 electric customers in Wisconsin and the Upper Peninsula of Michigan, approximately 470,000 natural gas customers in Wisconsin, and about 460 steam customers in metropolitan Milwaukee, Wisconsin. WG is a natural gas distribution public utility that serves approximately 600,000 natural gas customers in Wisconsin. WEPCO and WG are operating subsidiaries of Wisconsin Energy Corporation, a holding company based in Milwaukee, Wisconsin.

WEPCO has two physically separate steam utility systems that are known as the VA Steam operations and MC Steam operation. VA Steam operations provides steam service in downtown Milwaukee and the near south side of Milwaukee. MC Steam operations owns and operates the Milwaukee County Power Plant, which produces steam energy that is distributed to customers located on the Milwaukee County Grounds in Wauwatosa, Wisconsin.

Revenue Requirement

Settlement Agreement

Prior to submitting its filing in this proceeding, We Energies initiated discussions with the Settlement Parties and Commission staff regarding the possibility of limiting the number of contested issues in its rate application. The 2015 test-year adjustments that We Energies and the Settlement Parties agreed to resulted in an $82,618,000 decrease to Wisconsin retail electric revenue requirement, an $8,161,000 decrease to the WE-GO natural gas revenue requirement, a

$763,000 decrease to VA Steam revenue requirement, a $621,000 decrease to MC Steam revenue requirement, and a $15,313,000 decrease to WG natural gas revenue requirement. The settlement agreement also includes a 2016 step increase in retail electric rates of $26.6 million to reflect the fall-off of fuel and Treasury Grant credits, as well as the end of an amortization. In addition, the agreement includes a 2016 step increase for WG of $21.4 million for the West Central Lateral project and the fall off of the pension credit amortization. We Energies then used the resulting deficiencies and surplus after the settlement adjustments as the starting point for its filed rate change requests.

Numerous adjustments were agreed to by the Settlement Parties. The most noteworthy adjustments included the elimination of incentive and bonus compensation costs; reduction in the return on common equity (ROE) from 10.4 percent to 10.2 percent, with the financial common equity ratio remaining the same as currently authorized for WEPCO (51.00 percent); and reduction in the ROE from 10.4 percent to 10.3 percent return on common equity, with the financial common equity ratio to increase from 47.5 percent currently authorized to 49.5 percent for WG. Another notable adjustment included reducing electric revenue requirement by $5 million ($4.7 million Wisconsin jurisdiction) due to the reduction in carrying costs for a number of deferred amounts that WEPCO would have requested to earn at the long-term debt rate, which was forecasted to be 5.02 percent in the test year, compared to carrying costs that the Commission authorized at the short-term debt rate, which was forecasted to be 1.75 percent. WEPCO currently earns a return calculated at the short-term debt rate for its Power the Future escrow, its transmission escrow, and for deferrals related to MISO activities. Other adjustments were made to be consistent with prior Commission decisions, as well as adjustments to reflect recent cost trends and budget to actual analyses.

The issues that were not included as part of the settlement discussions were the cost of fuel in the test year, the 2008 settlement with Clean Wisconsin and the Sierra Club in the dispute about the WPDES permit for ERGS, and the 2014 SSR revenues received by WEPCO. In its filing in this proceeding, WEPCO included a $10.8 million increase for fuel in 2015 but did not include any costs for the WPDES settlement. WEPCO's filed revenue requirement also did not reflect any SSR revenue received in 2014.

Charter was not part of the settlement discussions and it indicated that the Commission should not regulate via settlement discussions that exclude the public and some of the intervening parties. Charter's position was that the Commission should have adjusted the settlement agreement revenue requirement to reflect a lower ROE, to protect Wisconsin ratepayers from Michigan's deregulation-induced stranded costs, to refund lease payments to We Power for the excessive downtime of ERGS, and to recapture promised but undelivered wholesale capacity sales revenue.

The Commission accepts the Wisconsin retail rate adjustments included in the settlement agreement between We Energies and the Settlement Parties. As part of a collaborative effort with the Settlement Parties, Commission staff analyzed test-year costs and revenues. Based upon that analysis, the rate adjustments agreed to by the Settlement Parties are reasonable.

The Commission is not persuaded by Charter's complaint about the settlement process and declines to make the adjustments requested by Charter to the settled revenue requirement.[3]

[3] The request of Charter and certain other parties for a reduction in ROE is discussed more fully later in this Final Decision.

While Charter did not participate in the negotiations, it had a full and fair opportunity to present its case and make its arguments for a reduction to the revenue requirement and ROE as part of these proceedings.

Uncollectible Accounts Escrow

One of the adjustments made by Commission staff that was ultimately agreed to by the Settlement Parties was to uncollectible accounts expense. WEPCO and WG are currently authorized to use escrow accounting treatment for WEPCO's residential electric and gas operations and for WG's residential gas operations. Accordingly, based on the adjustments made by Commission staff, agreed to by the Settlement Parties, and accepted by the Commission, WEPCO is directed to record $29,517,000 in uncollectible accounts expense for the electric uncollectible accounts escrow, which is comprised of $26,504,000 of net write-offs plus an amortization expense of $3,013,000. For WE-GO, it shall record $2,325,000 in uncollectible accounts expense for its uncollectible accounts escrow, which is comprised of $3,172,000 of net write-offs less a negative amortization expense of $1,900,000. For WG, it shall record $5,895,000 in uncollectible accounts expense for WG's uncollectible accounts escrow, which is comprised of $16,655,000 of net write-offs less a negative amortization expense of $10,760,000. These expense amounts, which are Wisconsin retail amounts, shall be recorded annually until the Commission authorizes a different amount to be recorded.

Regulatory Amortizations

Unless discussed separately in this Final Decision, the annual expense amounts itemized in exhibit Ex.-WEPCO/WG-Ackerman-4, Schedule 1, shall be recorded for all items listed for

2015 and 2016 or until the Commission authorizes a different amortization expense to be recorded.

Electric Fuel Costs

Pursuant to Wis. Admin. Code ch. PSC 116 (fuel rules), each of the five major, investor-owned Wisconsin electric utilities (IOU) must file a proposed fuel cost plan (monitored fuel costs) for each upcoming calendar year. Each year, after hearing, the Commission approves the utility's fuel cost plan and establishes the utility's rates in accordance with the approved fuel cost plan.

In addition, there are other fuel costs that are not listed in Wis. Admin. Code § PSC 116.02, and as such, are not included in a utility's approved fuel cost plan. The rates for these other fuel costs are reviewed and set in a general rate proceeding for the utility.

The Commission finds that a reasonable estimate of WEPCO's 2015 total company fuel costs (all fuel costs) for the test year is $1,011.061 million. The Commission finds that a reasonable estimate of WEPCO's 2015 fuel cost plan-year level of monitored fuel costs is $815.911 million. The test-year monitored fuel costs divided by the test-year estimate of native energy requirements of 26,339,688 MWh results in an average net monitored fuel cost of $30.98 per MWh. Appendix F shows the monthly fuel costs to be used for monitoring purposes.

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

PRB Coal Blending at ERGS

In 2011, WEPCO started planning to implement its ERGS Fuel Flexibility project with the goal of modifying the necessary equipment at the power plant to allow combustion of a blend of bituminous and PRB coals. ERGS was designed to burn bituminous coal but the delivered cost of that coal compared to PRB coal has changed significantly so that having the flexibility to burn PRB coal will result in overall savings for WEPCO's ratepayers. Blending levels may reach 100 percent PRB coal depending on the economics of the cost of the modifications to ERGS and the resulting fuel cost savings.

WEPCO's approved 2014 fuel cost plan reflected a 20 percent PRB coal blend rate at ERGS Unit 2 and no PRB coal burned at ERGS Unit 1. In January 2014, WEPCO fully converted ERGS Unit 2 to a 40 percent PRB coal blend rate and started burning a 20 percent PRB coal blend rate at ERGS Unit 1. In May 2014, WEPCO increased the PRB blend rate at ERGS Unit 2 to 60 percent. During the summer of 2014, WEPCO continued to test both 40 and 60 percent PRB blend rates at ERGS Unit 2 although the majority of that testing had been done at reduced loads due to operational issues including low coal inventory levels.

WEPCO's filed 2015 fuel cost plan reflected a 40 percent PRB coal blend rate at ERGS Unit 2 and no PRB coal burned at ERGS Unit 1. During Commission staff's audit in this proceeding, WEPCO proposed that a 40 percent PRB coal blend rate at ERGS Unit 2 and a 20 percent PRB coal blend rate at ERGS Unit1 was appropriate for 2015 based on its testing results experienced to date.

Commission staff noted that WEPCO had been conservative in its forecasting of attainable PRB coal blend rates at the ERGS units based on the experience of its fuel flexibility project during 2014. Commission staff proposed that a more aggressive 40 percent PRB coal blend rate should be forecasted for both ERGS units during 2015.

The Commission observes that WEPCO's approved 2014 fuel plan forecasts has resulted in fuel cost over-collections during the year due to higher than forecasted PRB coal blend rates. WEPCO has been conservative in its forecasts. Its testing of PRB blends in 2014 of both 40 and 60 percent PRB blends is indicative that a 40 percent blend at both units is more likely to occur. The Commission finds it reasonable that the 2015 fuel plan should reflect a 40 percent PRB blend rate for both ERGS units.

WEPCO testified that for any ERGS unit that has a PRB coal blend rate greater than 20 percent, a one- to two-week inspection outage should be scheduled. Commission staff agreed that it made sense for an inspection outage for an ERGS unit burning greater than 20 percent PRB coal and suggested that an additional one and one-half-week inspection outage be used. The Commission finds it reasonable to forecast that WEPCO will have an additional one and one-half-week inspection outage at each ERGS unit during 2015.

Uncontested Fuel Adjustments

During Commission staff's audit, it was discovered that interstate pipeline capacity costs for the Valley Power Plant were not included in WEPCO's filed non-monitored fuel costs. Further, an estimate of gas consumed during testing after conversion of Unit 2 to natural gas was also overlooked by WEPCO. As a result, it is reasonable to increase the 2015 non-monitored fuel forecasts by $3.6 million to reflect a forecast for interstate pipeline capacity costs for the Valley Power Plant and testing costs for Valley Unit 2 after its conversion to natural gas during 2015.

WEPCO proposed revising its modeling assumptions for auxiliary load at its power plants based on recent actual load data. Commission staff had an opportunity to review the load data and agreed to use the revised assumptions but failed to reflect the revised assumptions in its 2015 fuel forecasts. It is reasonable to increase 2015 monitored fuel forecasts by $1.7 million to reflect the revision of WEPCO's modeling assumptions for auxiliary load at its power plants.

The Commission finds it reasonable to accept and incorporate Commission staff's uncontested fuel adjustments, as adjusted by updates for coal contracts executed since Commission staff's fuel plan audit and the updated NYMEX futures settlement prices.

It is reasonable to decrease 2015 monitored fuel costs by $18.1 million to reflect the new coal contracts executed by WEPCO since Commission staff's audit in this proceeding.

It is reasonable to decrease monitored fuel costs by $3.9 million to reflect the updated forecasts based on the NYMEX futures settlement prices for natural gas, heating and crude oil prices as of October 15, 2014.

It is reasonable to decrease monitored fuel costs by $1.7 million to reflect the updated LMP forecasts based on the updated NYMEX futures settlement prices and the resulting effect on forecasted 2015 RTMP revenues.

In Order Point 34 from the Final Decision in docket 5-UR-106, the Commission determined that it was appropriate for the 2013 test year, and prospectively, to model WEPCO's ERGS units as economic in the MISO energy market during the non-summer months of the test year. WEPCO testified that during the time in which it is test burning PRB coal at an ERGS unit, it needs to dispatch that unit as must-run rather than economic in order to sustain a unit's operational testing even if the unit is not economic to the market. Commission staff did not oppose WEPCO's request for waiver from the Order Point 34 for the 2015 fuel plan. The

Commission finds it reasonable to waive Order Point 34 from the Final Decision in docket 05-UR-106 during 2015 for an ERGS unit while that unit is test-burning PRB coal during 2015.

MISO SSR Agreements

SSR costs result when a generation resource owner (GRO) wishes to retire[4] a generating unit because the cost to operate the unit is not economic relative to alternative energy sources available to the GRO but for which MISO determines that the unit must be maintained to ensure network reliability. MISO requires the generating unit to remain in service and the GRO is compensated for keeping the unit in service. An SSR agreement formalizes the amount of compensation to be received by the GRO and establishes an appropriate allocation of the compensation to the load serving entities (LSE) that benefit from the operation of the SSR unit. Several issues in this proceeding involve how, for state ratemaking purposes, this Commission should treat SSR costs and revenues arising from WEPCO's PIPP in the Upper Peninsula of Michigan.

Escanaba SSR Agreement

The Commission was first confronted with how to address SSR costs for ratemaking purposes in docket 4220-UR-118.[5] In that rate case, Northern States Power Company-Wisconsin (NSPW) requested that the Commission determine how SSR charges from MISO would be treated in subsequent rate proceedings. On March 4, 2013, the Federal Energy Regulatory Commission (FERC) issued an order approving an SSR agreement between MISO and the city

[4] In the case of the Presque Isle Power Plant SSR agreement filed with FERC on January 31, 2014, WEPCO requested to suspend operations at the plant. A subsequent SSR agreement was filed with the Federal Energy Regulatory Commission (FERC) on September 12, 2014, for the retirement of the plant.
[5] *Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates*, docket 4220-UR-118, Final Decision (PSC REF#: 178198)(Dec. 27, 2012).

of Escanaba, Michigan. At the time the Commission decided NSPW's rate case in that docket, SSR charges had not been assessed to Wisconsin utilities but were expected. The Commission concluded in that case, that there was not a sufficient basis at that time to determine how SSR charges should be treated, and directed Commission staff, IOUs, and interested intervenors to work together after January 1, 2013, to address the SSR cost issue and to bring that issue back to the Commission for a subsequent determination. In an order dated April 30, 2013, in docket 4220-UR-118 (Escanaba order) (PSC REF#: 184209), the Commission found it reasonable for each of the five major, Wisconsin IOUs to defer the net SSR costs through December 31, 2015, and the Commission would determine the appropriate accounting and ratemaking treatment beyond that date.

The Commission noted in that order the concerns of CUB and WIEG (referred collectively to in the Escanaba order as Wisconsin Customers) relating to the uncertainty of the costs and also their argument that "if utilities were being charged for SSR costs, there would also be a reduction in revenue sufficiency guarantee make-whole payments paid to the SSR unit as well as other MISO charges associated with changing a unit's status to SSR." CUB and WIEG therefore argued that those net SSR costs should be deferred. The Commission agreed:

> The Commission finds, for the reasons identified by the Wisconsin Customers, it reasonable to defer the net SSR costs through December 31, 2015. At that time, the Commission will determine the appropriate accounting and ratemaking treatment beyond that date.

(Escanaba order, at 3.)

Early Determination of Accounting Treatment of SSR Costs

In this proceeding, WEPCO proposed that the Commission could make a determination for WEPCO regarding the appropriate accounting treatment for SSR costs rather than waiting until after December 31, 2015, as directed in the Escanaba order. CUB, WIEG, and Charter argued that a decision concerning the appropriate ratemaking and accounting treatment for net SSR costs should not be addressed in this proceeding. The Commission agrees with the intervenors. It is reasonable for WEPCO to continue to include net SSR costs, pursuant to the Escanaba order, in its escrow accounting for transmission costs, on a temporary basis, through December 31, 2015, or until the Commission makes a determination on this matter.

WEPCO's PIPP SSR Agreements

In 2013, WEPCO lost a significant amount of Michigan retail load due to the Empire and Tilden mines and other customers in the Upper Peninsula of Michigan electing to take service from an alternative energy supplier under Michigan's retail choice law. On August 1, 2013, WEPCO submitted an Attachment Y request[6] to suspend operations of PIPP beginning February 1, 2014, and ending May 31, 2015.

On January 31, 2014, MISO filed with FERC an executed SSR agreement with respect to PIPP. This PIPP SSR agreement (Suspension SSR agreement) became effective February 1, 2014, and was set to expire on January 31, 2015. The PIPP Suspension SSR agreement had a variable component, which reimbursed WEPCO for PIPP's production fuel costs when dispatched, and a fixed component, which reimbursed WEPCO for O&M expenses, carrying costs of inventories, and ongoing capital expenditures incurred to keep PIPP operational. The monthly payment for the fixed component was $4.353 million.

[6] As part of its responsibility to maintain its network reliability, MISO requires a GRO to file an Attachment-Y when the GRO is considering to retire or mothball (suspend operations) any of its generating units. With the GRO's request for such status change, MISO studies the effect on system reliability, which may result in a possible SSR classification.

In a July 29, 2014, order, FERC revisited its order for the PIPP Suspension SSR agreement, replaced the allocation of SSR costs based on MISO's final load-shed study, and directed that the fixed component of the agreement be set for settlement conferences and hearing.

On April 15, 2014, WEPCO submitted an Attachment Y request with MISO to retire the PIPP units effective October 15, 2014. On September 12, 2014, MISO filed with FERC, a request to terminate the Suspension SSR agreement and to approve a Retirement SSR agreement with respect to PIPP. The PIPP Retirement SSR agreement was requested to become effective October 15, 2014, and set to expire on December 31, 2015.

The variable component under the PIPP Retirement SSR agreement is the same as in the PIPP Suspension SSR agreement but the fixed component was modified to include additional costs such as depreciation of, and a return on, PIPP rate base and associated taxes that were not reimbursed in the PIPP Suspension SSR agreement. This additional compensation accounts for most of the increase in the fixed component of the PIPP Retirement SSR agreement, which is now $8.085 million per month or about $97.0 million in 2015 on a total company basis. The PIPP Retirement SSR agreement contains a true-up provision for reconciling actual SSR-related costs/revenues to the forecasted costs/revenues.

In a November 10, 2014, order, FERC accepted termination of the PIPP suspension SSR Agreement and directed that cost components of the PIPP Retirement SSR Agreement be set for settlement conference and hearing.

Proposed Ratemaking Treatment in 2015 Test-Year of SSR Revenue

The 2015 test year in this proceeding, as proposed in settlement discussions, reflects the $4.353 million monthly payment received by WEPCO from MISO under the PIPP Suspension

SSR agreement. The anticipated annual payment of $52.2 million was used to reduce WEPCO's 2015 electric utility revenue requirement by $48.8 million reflecting the jurisdictional allocation to Wisconsin retail rates. With the PIPP Retirement SSR agreement, the 2015 MISO payments to WEPCO for the fixed component are anticipated to be $97.0 million or an increase of $44.8 million ($41.9 million Wisconsin jurisdiction).

WEPCO proposed two options for the treatment of anticipated 2015 PIPP SSR revenue: (1) escrow any additional revenue per the settlement reached earlier with the Settlement Parties, or (2) incorporate an estimate of the additional revenue as an offset to the 2015 electric revenue requirement and escrow only the difference between the estimate and actual.

CUB and WIEG proposed that the additional $41.9 million in SSR revenue received from the PIPP Retirement SSR agreement be included in WEPCO's 2015 electric revenue requirement. CUB and WIEG argued that including the additional SSR revenue in 2015 is appropriate because: (1) the original $48.8 million in SSR revenue was already accepted as a revenue requirement offset in the proposed settlement in this proceeding, and (2) including all of the anticipated revenue to be received by WEPCO in 2015 from MISO for the purpose of operating PIPP will be used appropriately to offset costs for PIPP's operations during 2015.

Commission staff offered as an alternative that any additional PIPP SSR revenue in 2015 be used to write off a portion of WEPCO's old transmission escrow balance that is currently receiving carrying costs at the weighted cost of capital.

It is reasonable that the anticipated additional SSR revenue received from MISO under the PIPP Retirement SSR agreement, amounting to $41.9 million on a Wisconsin jurisdictional basis, be included in WEPCO's 2015 electric revenue requirement in addition to the $48.8 million that was included in the agreement with Settlement Parties, for a total Wisconsin retail amount of $90.7 million that is reflected in WEPCO's 2015 electric revenue requirement. Using this revenue as an offset to the 2015 revenue requirement provides an immediate benefit to ratepayers.

Proposed Escrow Accounting Treatment for SSR Revenue

In making this decision, the Commission acknowledges that there is potential uncertainty of the amount of the revenue that WEPCO will actually receive from MISO under both PIPP SSR agreements. In addition, WEPCO will be required to make "uplift" payments for its share of the SSR costs for PIPP under MISO's tariffs. Both the amount of SSR revenue WEPCO will receive, as well as WEPCO's share of the uplift payments to MISO are matters still pending at FERC in several related dockets.[7] WEPCO proposed escrow accounting treatment for both the 2015 SSR revenue and uplift payments. CUB and WIEG agreed that the 2015 SSR revenue should be given escrow accounting treatment. It is therefore reasonable for WEPCO to utilize escrow accounting treatment for the 2015 PIPP SSR revenue. It is reasonable for WEPCO to record Wisconsin retail revenues of $90.7 million into a new escrow account in 2015. This mitigates any risks associated with the uncertainty as to the actual amount of SSR revenue WEPCO may receive.

In this proceeding, WEPCO proposed to include the SSR uplift payments that it is required to make to MISO for its share of PIPP in its existing escrow account for transmission costs, rather than monitored fuel costs, because these costs are incurred to maintain electric reliability in Michigan and are similar to other charges from MISO for reliability. CUB, WIEG, and Charter argued that a decision concerning the appropriate ratemaking and accounting treatment for net SSR costs should not be addressed in this proceeding. The Commission agrees

[7] *See, e.g.*, FERC Dockets ER14-1242, ER14-1243, ER14-2860, ER14-2862, ER14-2952, EL14-34, EL14-103, EL14-104, and EL15-7.

with the intervenors. It is reasonable for WEPCO to continue to include net SSR costs (per the Escanaba order) in its escrow accounting for transmission costs, on a temporary basis, through December 31, 2015, or until the Commission makes a determination on this matter.

Carrying Costs

WEPCO testified that interest on deferrals and/or escrow balances related to SSR revenue should accrue at the short-term debt rate consistent with the treatment authorized for the net SSR costs. CUB and WIEG argued that if the Commission does not offset WEPCO's 2015 electric revenue requirement with the additional $41.9 million PIPP Retirement SSR revenue, the carrying cost on the SSR revenue escrow balances should be at the weighted cost of capital. It is reasonable that the carrying costs on WEPCO's deferred or escrowed SSR revenue should accrue at WEPCO's authorized weighted cost of capital because this revenue, had it been precisely known, would be an offset to WEPCO's 2015 revenue requirement. Since the Commission is authorizing rates for both 2015 and 2016 in this Final Decision, this revenue will not be recognized and returned to customers until 2017.

Commissioner Nowak dissents.

Treatment of 2014 SSR Revenue

In 2014, WEPCO escrowed the uplift charges it had been assessed by MISO as required by the Escanaba order, but it did not escrow any SSR revenue it received in 2014. As part of this proceeding, the SSR revenue WEPCO received during 2014 under the PIPP Suspension and Retirement SSR agreements was an issue. Commission staff testified that it interpreted the Escanaba order as requiring Wisconsin utilities to defer SSR revenue as net SSR costs. CUB and WIEG testified that WEPCO received SSR revenue for reliability reasons and that revenue offsets operational costs that WEPCO's Wisconsin ratepayers had already paid in rates. WEPCO testified that the Escanaba order did not require the deferral of SSR revenue for providing SSR services and that any attempt to claw back the 2014 SSR revenue by deferring SSR revenue already received by WEPCO would be retroactive ratemaking.

The Commission acknowledges the difference in opinion concerning the interpretation of the Escanaba order regarding SSR revenue and what was meant by "net" SSR costs. The Commission, however, is the ultimate arbiter of what it meant or intended when it issued that order. At issue in the Escanaba order was how to address payments that utilities made to MISO (SSR costs), not revenue received in support of operating an SSR unit. No Wisconsin utility was in line to receive any SSR revenue under the Escanaba SSR agreement. When the Commission used the term "net" in the Escanaba order, it was referring to SSR costs less any revenue sufficiency payments—which is what the Wisconsin Customers were concerned with at that time as reflected in that order—and not SSR revenue less SSR costs. SSR revenue was simply not at issue in the Escanaba order. To read that order as applying to the very different facts presented in this proceeding is not a reasonable interpretation of the Commission's Escanaba order.[8] As a result, the Commission concludes that the Escanaba order does not require or authorize WEPCO to defer SSR revenue received in 2014 for the operation of PIPP as net SSR costs.

Absent a deferral, the Commission must treat that revenue just as it would treat any other unexpected cost or revenue incurred or received by a utility between rate cases. It is undisputed that WEPCO lost significant load (and the resulting sales) when the Empire and Tilden mines

[8] The dissent accuses WEPCO of "sitting on its hands" for purportedly not addressing the SSR revenue issue earlier. (Dissent of Commissioner Eric Callisto in this docket, at 4.) WEPCO correctly interpreted and applied the Escanaba order. It was CUB and WIEG who offered a different interpretation of that order and who could have raised this issue sooner and sought clarification pursuant to Wis. Stat. § 196.39. While the dissent may have preferred to see this issue addressed sooner, WEPCO, CUB and WIEG agreed that this issue would not be part of the settled revenue requirement issues.

switched to an alternative energy supplier. As WEPCO witness Ms. Wolter testified, this loss of load in Michigan reduced WEPCO's non-fuel revenue by $79 million on an annual basis. Neither these lost sales, nor the new SSR revenue, were anticipated or forecasted for the 2014 test year. As a result, WEPCO bears the risks and rewards of any such unexpected expenses or revenue under well-established ratemaking principles. While WEPCO is entitled under those principles to keep the 2014 SSR revenue, that revenue only partially off-sets the costs incurred by WEPCO by being required by MISO to keep PIPP operating.

While PIPP now provides FERC jurisdictional MISO SSR service, it is for this Commission to decide how costs and revenue associated with PIPP are to be treated for state ratemaking purposes. Here, the Commission concludes that it is reasonable and within this Commission's state ratemaking authority and discretion to reject the request that WEPCO defer any of the 2014 SSR revenue.

Commissioner Callisto dissents and writes separately.

WPDES Settlement

In 2008, WEPCO, along with Madison Gas and Electric Company and WPPI Energy, entered into a settlement agreement, subject to Commission approval of rate recovery, to help fund Lake Michigan improvement projects and to undertake a solar project. In this proceeding, WEPCO requested rate recovery for its portion ($3.3 million total company or $3.1 million for Wisconsin retail) of an annual $4 million payment to the Fund for Lake Michigan (Fund). In addition, WEPCO requested rate recovery of an additional $3.5 million on a Wisconsin retail jurisdictional basis to fund a solar project in 2016.[9]

[9] The project was planned be constructed in 2015 and its estimated in-service date was the end of 2015.

This Commission continues to find that the 2008 WPDES settlement was prudent and in the best interest of the ratepayers. However, that does not mean that recovery of all payments made as part of that agreement is a foregone conclusion. The express terms of the WPDES settlement agreement reserved for the Commission that determination on a case-by-case basis. The Commission finds it reasonable to continue to review the appropriateness of whether or not to include rate recovery of the costs associated with the WPDES settlement agreement on a case-by-case basis. This conclusion is consistent with the Commission's determination in docket 5-UR-106.

However, unlike the record in that prior proceeding, the record in this case supports recovery in rates for some of the payments proposed to be made pursuant to the WPDES settlement agreement. The Commission finds that it is reasonable to include the $3.1 million (Wisconsin retail) annual payment to the Fund in both the 2015 and 2016 electric revenue requirement for this proceeding because the Commission determines that the record clearly demonstrates that there are sufficient economic and environmental benefits to WEPCO's ratepayers to justify rate recovery. However, the same cannot be said as it relates to the solar project. There is insufficient record evidence as to how, in particular, WEPCO's customers would benefit from the project. WEPCO does not need the solar project for either its compliance with the Renewable Portfolio Standard or for the capacity, and the project costs for such un-needed capacity are significant. Therefore, the Commission concludes that it is reasonable to exclude the solar project costs from the 2016 electric revenue requirement because WEPCO did not demonstrate the benefit of the project to ratepayers. The Commission will continue to review the appropriateness of whether or not to include rate recovery of the costs associated with the WPDES settlement agreement on a case-by-case basis.

Commissioner Callisto dissents and would have allowed rate recovery for both payments to the Fund and for the solar project.

WG Sales Forecast

The Commission finds it reasonable to increase WG's sales revenue by $4.0 million dollars to reflect the additional sales associated with the conversion of the Valley Power Plant to natural gas. This adjustment is appropriate to be consistent with the forecast of electric fuel costs that include the Valley Plant conversion.

Treasury Grant Credits

WEPCO received Commission authorization to escrow the Treasury Grant credits in docket 5-UR-106 due to the uncertainty of the exact amount and the timing of the flow-through of the benefits to customers through bill credits in 2013 and 2014. WEPCO's filing in this proceeding included an additional $12.8 million benefit on a Wisconsin retail basis to flow through to customers in 2015. The fall off of this credit contributes to the 2016 step increase for electric operations. Because the actual amount to be received is still subject to Treasury audit and the timing of the flow-through to customers is subject to fluctuation in customer usage, the Commission finds it reasonable to continue escrow accounting treatment for the Treasury Grant credits though 2015 and into 2016 if necessary.

Section 199 Domestic Production Tax Deduction

WEPCO's filing included a $39.7 million Section 199 Domestic Production Tax Deduction benefit in the electric utility's 2015 test-year forecast that lowers the test-year revenue requirement by $14 million. However, the exact benefit that will actually be realized is highly dependent on many volatile variables that go into determining future taxable income. Because forecasting this tax deduction is highly uncertain, the Commission finds it reasonable to continue escrow accounting treatment for the Section 199 Domestic Production Tax Deduction.

Agriculture Service Program

The Commission first approved the Agriculture Service Program in 2002, when it was called the Dairy Farm Program, to stimulate WEPCO's farm community to take action on wiring code compliance, energy efficiency, and farm safety issues. Program costs were included in the conservation escrow until the last rate proceeding in docket 5-UR-106. The Commission removed the Agriculture Services program from the conservation escrow beginning in 2013 because the expenditures did not meet the definition of customer conservation established by the Commission in docket 5-BU-102.

WEPCO's Farm Rewiring program provides financial and technical assistance to agricultural producers to upgrade their on-farm secondary electrical systems. The farm rewiring program promotes energy conservation, reduces on-farm electrical system hazards, provides energy efficiencies, improves electrical system reliability, and decreases power quality issues. This program requires participating farms to meet the standards of the National Electric Code (NEC). Electricians performing work for the program are required to be licensed and to complete a farm wiring certification course including NEC updates. Farm rewiring program projects are inspected by State of Wisconsin Electrical Inspectors. Regulation through inspection ensures projects are done correctly and within budget.

The Commission finds it reasonable to authorize escrow accounting treatment for the Agriculture Service Program to ensure cost recovery and protect continuing funding levels for this program, ensuring program stability for future participants. Escrow accounting treatment is important for the success of this program in that WEPCO's farm rewiring program provides assistance to agricultural producers in addressing on-farm electrical system concerns. WEPCO shall record $1,317,000 of annual expense for the Agriculture Service Program until the Commission authorizes a different amount for it to record as expense.

Conservation Escrow

It is reasonable for We Energies to record the following amounts as expense to the conservation escrow until a new rate order is issued by the Commission authorizing different amounts to be recorded as expense. For WEPCO, it shall record $57,903,000 of annual expense, which consists of $46,604,000 of estimated expenditures and $11,299,000 of amortization of overspent amounts. For WE-GO, it shall record $7,883,000 of annual expense, which consists of $8,054,000 of estimated expenditures less a negative $171,000 of amortization of underspent amounts. For WG, it shall record $10,323,000 of annual expense, which consists of $10,692,000 of estimated expenditures less a negative $369,000 of amortization of underspent amounts. We Energies shall continue to record these expense amounts annually until the Commission authorizes different amounts to record as expense.

Depreciation Rates

The Commission finds it reasonable to calculate the revenue requirement in this proceeding using the depreciation rates approved in docket 5-DU-102.

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 Commission staff adjustments to WEPCO's filed electric, natural gas, and steam operating income statements and WG's natural gas operating income statements are appropriate. Accordingly, the estimated WEPCO electric, natural gas, and steam operating income statements and WG natural gas operating income statements at present rates for the 2015 test year, which the Commission finds reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

	WEPCO					
	WI Juris. Electric	WE-GO	VA Steam	MC Steam		WG
Revenue:						
Utility Sales	$ 2,894,623	$ 446,281	$ 23,828	$ 17,123		$ 649,310
Opportunity Sales	243,510	-	-	-		-
Other Operating Revenue	128,692	1,312	0	-		4,112
Total Operating Revenue	$ 3,266,825	$ 447,593	$ 23,828	$ 17,123		$ 653,422
Operating and Maintenance Expense:						
Fuel	648,044	-	-	7,770		-
Purchased Power	469,274	-	-	-		-
Purchased Gas		283,810	-	-		404,792
Other Production	637,919	-	-	-		-
Manufact. Gas Production		971	-	-		245
Gas Supply		1,534	-	-		1,959
Gas Storage		825	-	-		40
Steam Generation		-	-	4,968		-
Valley Steam Generation Transfer		-	7,507	-		-
Milw County Steam Generation Transfer		-	-	(2,637)		-
Transmission	253,390	5	-	-		9
Distribution	86,813	24,559	7,288	679		27,958
Customer Accounts	56,887	8,872	7	5		23,494
Customer Service	64,278	14,410	15	10		21,192
Sales Expense	0	0	-	-		(0)
Administrative and General	142,120	11,368	2,152	1,767		29,835
Total O&M Expense	$ 2,358,724	$ 346,352	$ 16,969	$ 12,562		$ 509,524
Depr, Decomm, & Amort	267,256	28,034	2,730	2,135		42,848
Taxes Other Than Income Taxes	120,417	6,992	1,058	868		10,090
Federal Income Tax	95,651	16,304	929	365		15,011
State Income Taxes	3,905	3,976	231	94		(1,395)
Deferred Income Taxes	45,218	2,119	(193)	(71)		14,330
Investment Tax Credits	(850)	(20)	(3)	(3)		(46)
Total Operating Expenses	$ 2,890,321	$ 403,757	$ 21,721	$ 15,949		$ 590,363
Net Operating Income	$ 376,504	$ 43,836	$ 2,107	$ 1,174		$ 63,060

Net Investment Rate Base

Summary of Average Net Investment Rate Base

In addition to the findings regarding the specific items discussed in this Final Decision, all other uncontested Commission staff adjustments to WEPCO's filed electric, natural gas, and steam and WG's natural gas average net investment rate bases are appropriate. Accordingly, the estimated WEPCO electric, natural gas, and steam and WG natural gas average net investment rate bases for the 2015 test year, which the Commission finds reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

	WEPCO				WG
	WI Retail Electric	WE-GO	VA Steam	MC Steam	WG
Plant	$ 8,935,734	$ 1,101,431	$ 78,878	$ 39,728	$ 1,872,763
Accum Depr	(3,280,404)	(610,777)	(45,938)	(16,960)	(855,185)
Net Plant	$ 5,655,330	$ 490,654	$ 32,940	$ 22,767	$ 1,017,578
Fossil Fuel Inventory	118,516	-	1,440	2,287	147
Gas Storage	-	35,358	-	-	45,873
Materials and Supplies Inventory	117,445	2,626	552	1,108	4,781
Deferred Income Taxes	(1,432,222)	(92,633)	(6,798)	(3,620)	(183,435)
Customer Advances	(26,130)	(819)	(37)	(20)	(9,003)
Average Net Investment Rate Base	$ 4,432,940	$ 435,187	$ 28,097	$ 22,523	$ 875,941

Financial Capital Structure and Dividend Restriction

A reasonable long-term range for WEPCO's common equity ratio, on a financial basis, is 48.5 to 53.5 percent common equity. Similarly, a reasonable long-term range for WG's common equity ratio, on a financial basis, is 47.0 to 52.0 percent. The exact level of the common equity ratio within that range should not be static, but rather should dynamically reflect the circumstances facing WEPCO and WG at a given time.

The Commission finds an appropriate target level for WEPCO's test-year average common equity measured on a financial basis is 51.0 percent. Further, an appropriate target level for WG's test-year average common equity measured on a financial basis is 49.5 percent.

In calculating capital structures, on a financial basis, this Commission has imputed debt associated with obligations not reported on balance sheets. Detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent is necessary for the Commission to make an independent judgment regarding WEPCO's financial capital structure. This information is most readily available from WEPCO and shall be provided as part of its next rate proceeding application. The information shall include, at a minimum, all of the following information:

1. The minimum annual lease and purchased power agreement obligations.
2. The method of calculation along with the calculated amount of the debt equivalent.
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 documentations when S&P and other major credit rating agencies' documentation is not available.

For the test year, the Commission finds that it is reasonable to impute $363,583,000 of debt equivalent associated with WEPCO's off-balance sheet obligations. Incorporating this estimate of off-balance sheet debt equivalent and other Commission determinations, WEPCO's financial capital structure for the test year consists of 51.00 percent common equity, 0.44 percent preferred stock, 39.14 percent long-term debt, 4.16 percent short-term debt, and 5.26 percent debt equivalent of off-balance sheet obligations.

WG's financial capital structure does not contain any debt-equivalent of off-balance sheet obligations. Incorporating the Commission's determinations, WG's financial capital structure for the test year consists of 49.50 percent common equity, 32.74 percent long-term debt, and 17.76 percent short-term debt.

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

Under Wis. Stat. § 196.795, the utility's capital needs must take precedence over non-utility needs in order for ratepayers to be protected. The identification of utility needs goes beyond foreseeable needs. WEPCO and WG 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, WEPCO may not pay dividends in excess of the amount forecasted in this case if those dividends cause the average annual common equity ratio, on a financial basis, to fall below the test-year authorized level of 51.00 percent. WG may not pay dividends above those estimates deemed reasonable in this proceeding without prior Commission approval, if after the payment of those dividends the actual average common equity ratio, on a financial basis, would be below the test-year authorized level of 49.50 percent.

The determination of whether the payment of dividends, over and above a typical or normal dividend, is appropriate can only be made at the end of the test year. Therefore WEPCO and WG shall wait until the end of the test year to pay additional dividends to the parent. Additional dividends may only be paid if their payment will not cause the common equity ratio, on a financial basis, to fall below the test-year authorized levels.

Ten-Year Financial Forecast

WEPCO's and WG's ten-year financial forecasts are useful to the Commission and shall be submitted in future rate proceedings. The ten-year forecasts 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, Commission staff deducted WEPCO's investment in common equity of American Transmission Company, LLC (ATC) net of deferred income taxes associated with transmission assets transferred to the ATC. In addition, Commission staff deducted WEPCO's and WG's investments in other non-utility items from the financial common equity to arrive at the common equity amount for the regulatory capital structure.

A reasonable utility ratemaking capital structure for the purpose of establishing just and reasonable rates for WEPCO for the test year consists of 51.90 percent common equity, 0.48 percent preferred stock, 43.04 percent long-term debt, and 4.58 percent short-term debt. Similarly, a reasonable utility ratemaking capital structure for the purpose of establishing just and reasonable rates for WG for the test year consists of 48.91 percent common equity, 33.13 percent long-term debt, and 17.96 percent short-term debt. These values are calculated from Commission staff's capital structure, by adjusting for the decisions in this proceeding.

Short-Term Debt

WEPCO's and WG's test-year capital structures contain approximately $287,496,000 and $207,309,000, respectively, of short-term debt. The interest rate associated with short-term indebtedness is the commercial paper rate. A reasonable estimate of the average cost of short-term commercial paper for the test year is 0.60 percent. This forecast is based on the average of test-year commercial paper rate estimates provided by the *Blue Chip Financial Forecasts* newsletter, adjusted by 20 basis points to reflect the spread between A-1/P-1 and A-2/P-2 rated commercial paper yields. This is a reasonable and objective method of determining short-term debt costs.

Long-Term Debt

WEPCO's embedded cost of long-term debt is 4.80 percent for the test-year. Similarly, WG's test-year embedded cost of long-term debt is 5.37 percent.

Preferred Stock

The average cost of WEPCO's preferred stock of 3.95 percent is reasonable for the test year.

Return on Equity

The Commission previously determined, in docket 5-UR-106, that a 10.40 percent return on utility common equity for WEPCO and a 10.50 percent return on utility equity for WG was reasonable. The settlement agreement between We Energies, the Settlement Parties, and Commission staff included an ROE of 10.20 percent for WEPCO and 10.30 percent for WG. Charter and Milwaukee Metropolitan Sewerage District (MMSD), who were not parties to the settlement discussions, argued that a lower ROE should be used.

In reaching its determination as to the appropriate ROE, the Commission must balance the needs of investors with the needs of consumers, with due consideration 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 ROE is often a contested issue in rate case proceedings. Here, the Settlement Parties agreed to a ROE, but other parties to this proceeding contested that settlement and argued for a lower ROE to reflect alleged decreased revenue risks in light of rate design changes.

Given the above-mentioned considerations, the Commission finds that the balance is struck most reasonably in this proceeding by accepting the settlement and authorizing an ROE of 10.2 for WEPCO and 10.3 for WG. While certain parties argued that a lower rate of return is appropriate based upon the Commission's approval of increased fixed charges, the record in this cases does not establish a direct, identifiable reduction in an investor's required return.[10] Absent such a showing, the Commission is also not persuaded that there are sound public policy reasons at this time for setting a lower ROE simply because the Commission has determined an increase in the amount of fixed charges is appropriate.

The Commission determines that a 10.20 percent ROE for WEPCO and 10.30 percent for WG is reasonable.

Commissioner Callisto dissents on the ROE for WEPCO and writes separately.

[10] The dissent states as foregone conclusions that the Commission "knows that increasing fixed customer charges reduces a utility's risk" and that "there is a direct relationship between increasing fixed charges and financial risk is not in question", and cites one statement by Dr. Cicchetti. (Dissent of Commissioner Eric Callisto in this docket, at 5.) That is hardly the type of substantial evidence necessary to support the sweeping conclusory statements offered by the dissent.

Using a 10.20 percent ROE, WEPCO's 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 (000's)	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	$3,261,145	51.90	10.20%	5.29%
Preferred Stock	30,450	0.48	3.95	0.02
Long-Term Debt	2,704,231	43.04	4.80	2.06
Short-Term Debt	287,496	4.58	0.60	0.03
Total Utility Capital	$6,283,322	100.00		7.40%

The weighted cost of capital of 7.40 percent is reasonable for WEPCO for the test year. It generates an economic cost of capital of 10.94 percent and a pre-tax interest coverage ratio of 5.23 times, on the regulatory capital structure.

Using a 10.30 percent ROE, WG's 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 (000's)	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	$564,493	48.91	10.30%	5.04%
Long-Term Debt	382,308	33.13	5.37	1.78
Short-Term Debt	207,309	17.96	0.60	0.11
Total Utility Capital	$1,154,110	100.00		6.92%

The weighted cost of capital of 6.92 percent is reasonable for WG for the test year. It generates an economic cost of capital of 10.30 percent and a pre-tax interest coverage ratio of 5.45 times, on the regulatory capital structure.

Rate of Return on Rate Base

The composite cost of capital must be translated into a rate of return that can be applied to the average net investment rate base and used to compute the overall return requirement in dollars. The estimate of WEPCO's average net investment rate base plus Construction Work in

Progress (CWIP) for the test year is 87.63 percent of capital applicable primarily to utility operations plus deferred investment tax credits. The estimate of WG's average net investment rate base plus CWIP for the test year is 83.13 percent of capital applicable primarily to utility operations plus deferred investment tax credits. These estimates reflect all appropriate Commission adjustments and are reasonable and just 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, an adjustment must be added to the return on net investment rate base. In considering whether to authorize a current return on any portion of CWIP, the Commission's standard practice has been to consider a company's test year financing, cash flow requirements, and forecasted amount of construction activity. Providing a current return on CWIP today helps to smooth rates over time. A current return on CWIP mitigates rate increases tomorrow and beyond because ongoing rate base will be lower. This Commission has not required a finding of financial distress before allowing a company to earn a current return on CWIP.

Given both WEPCO's and WG's financing and cash-flow requirements in the test year as well as the forecasted amount of construction activity, the Commission finds it reasonable to allow electric operations to accrue Allowance for Funds Used During Construction (AFUDC) on 100 percent of CWIP associated with the Twin Falls Hydro project. The Commission also finds it reasonable to allow WEPCO to accrue AFUDC on 100 percent of CWIP associated with the Fuel Alternatives Study for VA Steam, the Maximum Achievable Control Technology (MACT) Compliance project for MC Steam, and the West Central Lateral project for WG. It is also reasonable to allow a current return on 50 percent of all other electric, natural gas, and steam utility CWIP for the test year.

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

	WEPCO				
	Electric	WE-GO	VA Steam	MC Steam	WG
Cost of Capital	7.40%	7.40%	7.40%	7.40%	6.92%
Average Percent of Utility Investment Rate Base plus CWIP to Capital Applicable Primarily to Utility Operations	87.63%	87.63%	87.63%	87.63%	83.13%
Adjusted Cost of Capital to Derive Percent Return Requirement Applicable to Net Investment Rate Base	8.45%	8.45%	8.45%	8.45%	8.33%
Total Average CWIP Balances ($000)	$ 257,161	$ 15,980	$ 493	$ 3,094	$ 82,284
Percent of CWIP Receiving Current Return	30.64%	48.03%	46.96%	5.89%	3.26%
Amount of CWIP Receiving Current Return ($000)	$ 78,802	$ 7,675	$ 231	$ 182	$ 2,681
Current Earnings on CWIP Receiving Current Return at the Adjusted Cost of Capital	$ 6,659	$ 649	$ 20	$ 15	$ 223
Average Net Investment Rate Base	$ 4,432,940	$ 435,187	$ 28,097	$ 22,523	$ 875,941
Adjustment to Required Return to Provide a Return on CWIP	0.15%	0.15%	0.07%	0.07%	0.03%
Regulatory items at specified rate	0.01%	0.00%	0.00%	0.00%	0.00%
Adjusted Return Requirement on Utility Net Investment Rate Base	8.60%	8.60%	8.52%	8.52%	8.36%

Revenue Requirement

On the basis of the findings in this Final Decision, a $11,235,000 decrease in WEPCO's electric utility revenues, a $10,660,000 decrease in WE-GO's natural gas utility revenues, a $481,000 increase in WEPCO's VA Steam utility revenues, a $1,241,000 increase in WEPCO's MC Steam utility revenues, and a $17,097,000 increase in WG's natural gas utility revenues, are reasonable for the purpose of determining reasonable and just rates for 2015 in this proceeding. In addition, on the basis of the findings in this Final Decision, an additional $26,614,000 increase in WEPCO's electric utility revenues and a $21,400,000 increase in WG's natural gas utility revenues are reasonable for the purpose of determining reasonable and just rates for 2016 in this proceeding. These increases and decreases are computed as follows:

	WEPCO				WG
	Electric	WE-GO	VA Steam	MC Steam	Natural Gas
Pro Forma Return on Average Net Investment Rate Base at Present Rates	8.49%	10.07%	7.50%	5.21%	7.20%
Required Return on Average Net Investment Rate Base	8.60%	8.60%	8.52%	8.52%	8.36%
Earnings Deficiency (Excess Earnings) as a Percent of Average Net Investment Rate Base	0.11%	(1.47%)	1.02%	3.30%	1.16%
Average Net Investment Rate Base (000's)	$4,432,940	$435,187	$28,097	$22,523	$875,941
Amount of Earnings Deficiency (Excess Earnings) on Average Net Investment Rate Base (000's)	$4,926	$(6,415)	$286	$744	$10,127
Revenue Deficiency (Excess Revenue) to Provide for Earnings Deficiency (Excess Earnings) Plus Federal and State Income Taxes (000's) before Adjustments	$8,233	$(10,699)	$478	$1,241	$16,917
Tax Asset & Liability Settlement Items (000's)	$(2,326)	$39	$3		$180
Carrying Cost on ERGS Fuel Flex (000's)	$(2,482)				
Treasury Grant Refund (000's)	$(12,804)				
Staff Audit Adjustment – Fuel Losses (000's)	$(1,857)				
2015 Adjusted Revenue Deficiency (Excess Revenue) to Provide for Earnings Deficiency (Excess Earnings) Plus Federal and State Income Taxes after Adjustments (000's)	$(11,235)	$(10,660)	$481	$1,241	$17,097
2016 Step Increase					
Wisconsin Fuel Deferral	$18,900				
Treasury Grant Refund	$12,804				
CSAPR Amortization	$(5,090)				
West Central Lateral & Pension Fall Off					$21,400
Total 2016 Step Increase	$26,614				$21,400

Embedded Electric Cost of Service

WEPCO submitted the results of an embedded electric COSS as the basis for its customer class revenue allocation for electric service. The results of the WEPCO COSS reflect WEPCO's preferred cost allocation methodologies including a 100 percent demand allocation for production plant, a 4-coincident peak demand (4CP) production demand allocation, a distribution cost allocation based on a minimum-system/minimum-intercept cost classification approach, and separate allocations for single-phase and three-phase primary distribution costs. WIEG provided the results of its preferred COSS which is a variant of the WEPCO 4CP COSS approach. Commission staff presented the results of four additional studies prepared by WEPCO at Commission staff's request. The studies presented by Commission staff reflect an array of COSS approaches typically presented in Commission proceedings that were, in this case, not included in the COSS evidence provided by WEPCO. The four studies presented by Commission staff reflect modifications to the WEPCO COSS so as to include a 12-coincident peak (12CP) production demand allocation, a demand and energy allocation for production plant and production O&M expense, and a 100 percent demand allocation of distribution costs such as poles, conductors, conduit, and line transformers. CUB did not prepare a COSS itself but did provide testimony discussing the studies prepared by WEPCO, WIEG, and Commission staff. CUB indicated a preference for three of the studies presented by Commission staff.

While differing in opinion in limited areas, WEPCO and WIEG preferred COSS methods which allocate production plant expenses on a 100 percent demand basis, using a 4CP allocation, as well as WEPCO's distribution cost allocation approach. These two parties believe that these COSS allocation approaches most accurately reflect their view of utility cost causation. Commission staff expressed some concerns over the use of a 100 percent demand allocation for production plant, as well as the use of a 4CP production demand allocation. Commission staff suggested that a 12CP production demand allocation may more appropriately reflect WEPCO's overall capacity needs. Similarly, Commission staff suggested that a production plant allocation method that recognizes demand and energy related costs may more accurately reflect the diversity of production plant types within WEPCO's generation portfolio. CUB expressed similar concerns regarding WEPCO and WIEG's preferred COSS approaches. Additionally, CUB disagreed with WEPCO's distribution allocation approach, believing that any minimum system cost classification approach, like that used by WEPCO, overstates the extent to which distribution costs vary by customer. CUB expressed a preference for the 100 percent demand allocation method used in one of Commission staff's studies for distribution costs. Charter also did not provide the results of its own COSS, but indicated a general agreement with WEPCO and WIEG on allocation methods, believing those approaches to better reflect Charter's view of cost causation.

No consensus was reached by the parties over the course of this proceeding regarding COSS methodologies. The record in this proceeding contains a vigorous and thorough vetting of the COSS methods presented, which is accompanied by extensive quantitative evidence illustrating the effect these different methods have on utility COSS results. This Commission's long standing practice is to consider the results of several COSS for the purposes of allocating test year revenue responsibility. The evidence in this proceeding supports a continuation of this practice. The Commission finds it reasonable to consider the results of all COSS in the record for the purposes of class revenue requirement allocation.

As will be discussed below, WEPCO requested that the Commission authorize an increase in the facilities charges for residential and small commercial electric customers that some of the parties contested. WEPCO, CUB, the Environmental Law and Policy Center (ELPC), RENEW Wisconsin (RENEW), and Commission staff all submitted testimony regarding fixed costs, and what utility costs, are appropriate to consider for the purposes of setting fixed charges.

WEPCO provided the results of a functionalized cost analysis that suggested that the embedded customer-related cost for the residential and small commercial class is approximately $16 per customer. Commission staff provided the results of an alternative analysis that considered a narrower range of costs. This analysis suggested a customer-related cost of $11.60 per customer for residential and small customers. CUB, ELPC, and RENEW suggested that the Commission primarily consider issues such as public policy, fairness, and economic efficiency over the short and long term in order to determine the level of just and reasonable fixed charge rates. CUB also indicated that its own analysis suggests that, to the extent that the Commission did wish to base fixed charges on utility fixed costs, customer-related costs under WEPCO's COSS that do not vary with the size of the customer sum to less than $10.50 per month. The Alliance for Solar Choice (TASC) did not submit testimony regarding utility COSS and fixed charges but indicated in its brief that it supported CUB, ELPC, and RENEW's positions on fixed charges as they relate to utility cost and COSS.

While the Commission recognizes that the identification of specific utility costs as the basis for decisions on fixed charges would provide additional clarity to rate case proceedings, the Commission finds that it is not necessary at this time to do so. Identifying specific utility costs for inclusion in fixed rates would require this Commission to choose one COSS, which would be contrary to long standing Commission practice, and inconsistent with its decision regarding COSS as they relate to customer class revenue allocation. Absent substantial evidence supporting a change in Commission practice, this Commission finds it reasonable to instead consider the setting of fixed charges as a policy decision, and to consider state and Commission policies, fairness, and economic efficiency over the short and long term when setting fixed charge rates for residential and small commercial customers.

Electric Revenue Allocation

WEPCO initially proposed an electric revenue allocation for the 2015 test year based on a $52.3 million increase (1.81 percent) that included above average increases for the residential, and medium commercial classes, and decreases or slight increases for the small commercial, large commercial/industrial, lighting, and miscellaneous classes. Commission staff proposed an alternative electric revenue allocation for the 2015 test year based on a $44.5 million increase (1.54 percent) that had a narrower range of increases and decreases. This included above average increases for the residential classes and most of the large commercial/industrial classes, slightly below average increases for the small commercial classes, and decreases or slight increases for the medium commercial, lighting, and miscellaneous classes. CUB proposed a uniform electric increase for all classes for the 2015 test year based on a $2.7 million increase (0.1 percent), which is the result of netting SSR revenue credits against the Commission staff's proposed increase. The final electric revenue change for 2015 is an $11.2 million decrease (0.39 percent).

The electric revenue increases for 2016 proposed by WEPCO, Commission staff, and CUB all reflect the fact that the fuel deferral credit, bio-mass tax grant credit, and a CSAPR amortization end on December 31, 2015. This will result in an overall 0.92 percent increase in electric rates for 2016 above the 2015 rate levels. These credits apply to electricity sales, therefore the residential, small commercial, medium commercial, lighting, and miscellaneous classes that have smaller energy usage will get a lower than average increases for 2016 and large commercial and industrial classes will get higher than average increases for 2016.

Consistent with the determinations the Commission has made in previous rate proceedings, the Commission finds that it is useful to take into account the results of a number of different cost of service studies in addition to other factors such as rate stability and bill impacts when making a determination on class revenue allocation in this case. The Commission finds that the electric revenue allocations for 2015 and 2016 shown in Appendix B are reasonable.

Commissioner Callisto dissents. He would have allocated consistent with Commission staff's recommendation.

2005 Wisconsin Act 141 (Act 141) Costs in Base Rates

Both WEPCO and Commission staff proposed new Act 141 rate factors to reflect conservation costs that are included in the base electric rates, which are essentially the same. This is necessary for determining the correct billings for the large energy customers (LEC), since Act 141 limits the amount these LECs pay for certain conservation costs to the levels they paid in 2005 plus adjustments for inflationary increases. Commission staff also proposed that WEPCO adopt the accounting treatment of Act 141 revenue with respect to the LECs that is used by the other large IOUs in Wisconsin. The Commission finds that the Act 141 rate factors proposed by Commission staff that are shown in exhibit Ex.-PSC-Albrecht-1 to be reasonable. The Commission also finds it reasonable to require WEPCO to adopt the accounting treatment of Act 141 revenue with respect to the LECs that is used by the other large IOUs in Wisconsin.

Electric Rate Design

WEPCO proposed an electric rate design that includes increases in facilities charges, and lesser increases in energy charges for the residential and small commercial customers. For the medium and large commercial and industrial rate classes, the proposal includes increases in demand charges and lesser increases in energy charges. WEPCO also included a proposal to change the basis for determining the billed demand for the high-voltage primary customers from the highest 15-minute on-peak interval to the highest hourly on-peak interval, within the billing period. Commission staff presented an electric rate design that limited the facilities charge increases to 20 percent, and increases in the demand charge revenue that were less than WEPCO, but greater than WEPCO’s proposed increase in energy charge revenue.

The Commission finds that the overall electric rate design proposed by WEPCO is reasonable, in general, except for certain specific details as noted in this Final Decision. The Commission finds that Commission staff’s proposed demand and energy charges for the customer classes that are demand-metered, as shown in exhibit Ex.-PSC-Albrecht-1, are reasonable because these rates mitigate the range of intra-class impacts for the Cp customers. The authorized rates appear in Appendix B.

Commissioner Callisto dissents. He would have followed Commission staff’s recommendation.

WIEG proposed that WEPCO be directed to file seasonally differentiated energy charges in its next base rate case. The Commission finds that WEPCO shall work with WIEG, other interested stakeholders, and Commission staff to evaluate its electric cost-of-service with respect to the seasonality of its costs. WEPCO shall develop and submit a seasonally-differentiated electric rate design proposal in its next base rate proceeding.

Facilities Charges

WEPCO's electric rate design proposal includes increasing the fixed facilities charge from $9.13 to $16.00 per month, and decreasing the variable energy rates, for a variety of residential and small commercial customer classes. WEPCO's intent with these changes is to send more accurate price signals, reduce intra-class subsidies, and to more fairly set rates by better aligning customer charges with the costs customers cause. Commission staff proposed limiting the increase in facilities charges to 20 percent, along with changes in energy charges that produce lesser bill impacts for most customers. CUB opposed WEPCO's increases for the facilities charges. Instead, CUB proposed maintaining the current facilities 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. WIEG generally supported the WEPCO rate design proposal.

WEPCO'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 facilities charges have a direct relationship to the variable energy charges in customer classes 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 facilities charges, a dollar less needs to be recovered from the energy charge. The converse is also true; if the facilities 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 facilities 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, WEPCO 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.[11] 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 facilities 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

[11] 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.

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

WEPCO urged the Commission to increase the facilities charge to move it closer 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 general categories of 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 and one that allows it to provide the general support, such as billing, needed to administer its utility service. 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. TASC witness Mr. Friedman agreed that “[t]he utility’s grid is still important to providing consistent and reliability service.” (Direct-TASC-Friedman-6.) RENEW witness Mr. Rabago conceded that customers who own their own generation cause the utility to incur those costs to the same extent as customers who do not own their own generation. (Tr., 148-149.) WEPCO requested that the Commission consider facilities 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, as WEPCO's past rate designs have, 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. In setting just and reasonable rates, the Commission considers this general framework and determines what the appropriate facilities charge and variable energy charges should be for each customer class.

The Commission agrees with WEPCO that the analysis of an appropriate facilities 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 facilities 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. The customer 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, WEPCO provides a compelling case that its facilities 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 a determination is made that, in principle, facilities charges should generally align with fixed costs, the question becomes what those fixed costs actually are. Here, the Commission relies upon its long standing experience and approach to COSS. COSS 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. Evidence in the record established that WEPCO’s fixed costs exceed its proposed facilities charge. Thus, it is sufficient in this case that WEPCO’s proposal moves the facilities 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.

The intervenors requested the Commission make adjustments to the facilities charge for public policy reasons. RENEW and ELPC argued that the Commission should maintain a lower facilities charge without regard to the utility's fixed costs in order to be consistent with energy priority laws that support conservation, the development of renewable energy, and energy efficiency measures. It may be true that raising the facilities charge could have an incidental effect upon the payback period of certain energy efficiency measure and renewable energy resources. However, even under WEPCO's proposal, over 80 percent of a typical customer's bill will remain variable. Thus, the intervenors' concerns are overstated.

More importantly, the primary purpose of rate design is not its effect on 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.

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 also argued that lowering the energy charge was not consistent with the Energy Priorities Law (EPL) because the proposed rate design would encourage customers to consume more 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 run afoul of 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 the intervenors' theory, such a credit would be improper 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 facilities charge. This is clearly not a reasonable construction of the statute.[12]

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), and 196.025 (1) (ar). Thus, the law

[12] 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. (Dissent of Commissioner Eric Callisto in this docket, at 12.) If the law were applied as certain intervenors suggest, any vote to increase the fixed customer charge would violate it.

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.

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 facilities 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.

ELPC and RENEW also argued that the effect of this rate design change will fall disproportionately upon low-income users. WEPCO, 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. Furthermore, the total dollar bill impact of these changes is relatively small.

While the facilities 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 ELPC and RENEW's concerns, while worth consideration, are 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 no dispute that there are certain fixed charges incurred in providing utility service. (Direct-WEPCO/WG-O'Sheasy-2; 1-6; Rabago, Tr. 138:10-13 and 147; 18-23.) The dispute then focused on which specific costs could properly be labelled as fixed, compared to variable.
In WEPCO's view, the appropriate fixed costs to include in the facilities charge are:
"all customer-related costs … identified in the cost-of-service study … shown in exhibit Ex.-5 WEPCO/WG-Rogers-12 Schedule 32." (Direct-WEPCO/WG-Rogers-35.)

WEPCO Witness Mr. Rogers specifically identified the categories of costs that are partly allocated to the customer-related cost function. His analysis calculated the total fixed cost for the average residential customer to be $16.55 per month. RENEW witness Mr. Rabago did not dispute this assessment. (Tr., 150-151.) WEPCO proposed raising the facilities charge to $16.00 per month for both single phase and the three-phase residential customers and small commercial customers.

WEPCO did not request the facilities charge include any of the demand-related costs at this time, but requested instead that the facilities charge be increased to collect most if not all of the customer-related fixed costs. The record in this proceeding clearly demonstrates the present disconnect between the amount of fixed charges WEPCO currently assess its small customer class and the amount of fixed costs incurred to serve those customers. As WEPCO witness Mr. Rogers testified:

> Based on the results of our cost-of-service study, about 14% of the costs to serve the small customer class are customer-related fixed costs, but currently only about 8.5% of our costs are recovered by the facilities charge. Our proposed facilities charge would recover almost all of the customer-related costs. Over 61% of the costs to serve the small class are demand-related fixed costs. All of these costs are and will continue to be recovered by the variable energy charge. A demand charge may be the most appropriate way to recover demand-related fixed costs, but our metering infrastructure is not currently capable of supporting demand charges for the small customer class, so we are not proposing that at this time. The split between fixed and variable costs and cost recovery through the facilities charge and energy charge is illustrated in the graph in exhibit Ex.-18 WEPCO/WG-Rogers-15 Schedule 3.
>
> As I explained in my direct testimony, our cost-of-service study shows, for example, that 14.1% of the total cost of serving small customers takes the form of "customer costs" such as metering costs, service drop costs, accounting costs, customer service costs, and uncollectibles. This is illustrated in Exhibit WEPCO/WG-Rogers-15 Schedule 3. Schedule 32 of Ex.-WEPCO/WG- Rogers-12 shows that for the 1.1 million small electric customers we serve, these customer costs total $217 million per year, or just under $200 per customer per year. These are costs that are fixed in the sense that they do not vary with the amount of energy a customer purchases from the utility. These costs are caused by every customer who is hooked up to our system. Yet, as I also stated in my direct testimony, only 8.5% of total costs are recovered through a fixed facilities charge. That means that almost 40% of these customer costs, which do not vary with energy purchased from the utility, are being collected through energy charges. Our proposal would increase the facilities charge so that nearly all of these fixed customer costs are recovered through the facilities charge. Since every customer who is hooked up to our system causes these costs, under our proposal every customer would pay a facilities charge that more closely reflects them. This approach is consistent with the principle of cost causation and it is fair.

(Rebuttal-WEPCO/WG-Rogers-2 to 3.)

WEPCO witness Mr. Rogers also presented testimony that the variable cost of energy as represented by the marginal cost of energy has an approximate value of $0.0301 per kilowatt-hour (kWh), which is significantly lower than the current energy charge, of $0.13945 per kWh. Thus, WEPCO's analysis showed a significant difference between the way costs are incurred by the utility (fixed versus variable) and how the customers pay for it. Because the revenue requirement is the same within each class, this means that low energy users pay for less of the fixed costs than they cause the utility to incur. A graph in Mr. Rogers' testimony (Direct-WEPCO/WG-Rogers-37), shows WEPCO's current fixed and variable revenue differ considerably from its fixed and variable costs. This is because, like many utilities, WEPCO's current rates are 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.

It is undisputed that this misalignment results in under-recovery. As WEPCO witness Mr. O'Sheasy observed:

> If some portion of fixed cost, such as customer cost, is recovered via the volumetric energy charge, then when actual sales fall short of forecast, fixed costs tend to be under-recovered. For periods of sustained economic underperformance, the shortfall can accelerate the need for a rate case and degrade the utility's earnings between rate cases, adversely affecting the utility's realized rate of return and increasing its financing cost. The opposite impact upon earnings can occur if energy sales are greater than necessary, but this is less likely with the prevailing economic environment. Also, including customer-related or other fixed costs in a utility's energy charge will create a price distortion from incremental cost thereby making it difficult for users to make wise economic decisions.

(Direct-WEPCO/WG-O'Sheasy-6.)

> Wisconsin Electric is typical of the industry in that its recovery of facilities/customer-related costs occurs partially through the facilities charge, with the remainder being recovered in the energy charge. The utility estimates that, for test year 2013, the customer-related facilities charge of the Residential and Small Commercial classes collects between 55% and 75% of customer-related costs. The result is that considerable customer-related costs, roughly $75 million by Wisconsin Electric estimation, are recovered via the volumetric energy charge. As a result, sales growth shortfalls can translate into million dollar cost coverage shortfalls. … Even though under-recovery of customer-related cost via a customer charge occurs in the industry, such under-recovery is none-the-less inefficient.

(Direct-WEPCO/WG-O'Sheasy-7.)

Based upon this record evidence, the Commission is convinced that there is a significant misalignment between fixed costs and fixed charges that must be addressed. Failing to do so perpetuates distorted price signals which means that higher-use customers are paying some of the costs that lower-use customers cause. 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.

The Commission is not persuaded with the arguments that an increase in fixed charges to the levels proposed by WEPCO will have a detrimental impact on energy efficiency, conservation or the development of renewables.[13] The Commission agrees with WEPCO witness Mr. O'Sheasy that "conservation should be targeted at reducing inefficient usage by setting price at or near avoided cost as opposed to conservation merely for the sake of reducing usage." (Direct-WEPCO/WG-O'Sheasy-9r.) Further, "[i]f you inflate the price of energy by including customer cost, you make investments in energy efficiency look more attractive than

[13] The dissent is critical of the Commission's determination and, for "illustrative purposes" impermissibly resorts to non-record evidence in an attempt to demonstrate that increasing fixed charges may impact energy efficiency. (Dissent of Commissioner Eric Callisto in this docket, at 11, fn. 29.)

they really are, based on the cost of the energy." (Rebuttal-WEPCO/WG-O'Sheasy-15r.) Additionally, whether shifting of costs between fixed charges and energy charges is material in the context of the development or payback on renewable energy projects, the Commission must consider the impact of rate design on all customers.

The Commission also is not convinced based upon the record evidence that approving WEPCO's proposal will disproportionately impact low-use and/or low-income users or will cause rate shock. As WEPCO witness Mr. Rogers noted: "No customer would have a bill increase of over $7 per month. Even with the overall rate increase of 4.2% for the Rg1 class, about 5% of Rg1 customers will see a decrease in their bills due to the shift in revenue recovered from the energy charge to the facilities charge."

While some intervenors urged different results for policy reasons, there is no debate that utilities incur basic costs to provide backup service or access to the grid, regardless of the level of energy used or demand placed on the system. 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 facilities charges should be increased to more closely reflect WEPCO's fixed costs to provide basic service to a customer. The Commission determines that it is a reasonable balance, after weighing the testimony and policy arguments presented by the parties, to set the facilities charge at $16.00 per month for the residential classes and small commercial classes.

Commissioner Callisto dissents and writes separately.

Fixed Charges for Single and Three-Phase Customers

WEPCO, like some other Wisconsin utilities, distinguishes between customers who receive service at single phase and three phase in certain cost allocation contexts. As discussed above, WEPCO proposed increasing the single phase customers' facilities charge from $9.13 to $16 and decreasing the three phase customers' facilities charge from $18.25 to $16.00. WEPCO presented testimony that three-phase service may actually be less expensive than single-phase service, despite requiring more sophisticated meters, because the cost of the three-phase system does not include the secondary system cost. (Direct-WEPCO/WG-Rogers-35.) In the Commission's decision in docket 6690-UR-123, the Commission approved different facilities charges for single and three phase customers. While the record in this docket does not support such a differential for WEPCO's customers, the Commission finds that further analysis of this issue by WEPCO is warranted. WEPCO shall examine in its next rate case proceeding whether or not there is or should be a fixed facilities cost differential for single and three phase customers.

Extra Meter Charge

In this proceeding, WEPCO proposed to increase the charges for an extra meter from $1.41 per month to $3.42 per month for residential and small commercial customers. WEPCO stated the extra meter charge is intended to recover more than the cost of the meter and the service drop, to include recovery of customer accounting and service costs associated with the extra meter. Commission staff testified that the proposed increase to the meter charge exceeded the utility's costs for the extra meter and service drop.

The Commission finds that WEPCO did not provide sufficient evidence to justify its proposed increase to the full amount requested. While the record does support an increase to account for the cost associated with the extra meter and the service drop, the Commission is not persuaded the recovery of the other costs sought by WEPCO in this extra meter charge are appropriate. Consequently, the Commission concludes that an increase to the extra meter charge from $1.41 per month to $1.81 per month for small customer classes and an increase to $5.23 per month for medium and large customer classes is reasonable.

Interruptible Credits

Interruptible service allows a utility to control a portion of a customer's load. During periods of peak system demand, the customer's service is interrupted. The utility provides interruptible service at a lower rate than its general service rates. Interruptible credits are available under the CpFN, Cg3, and Cp3 tariffs to customers who wish to designate some or all of their load as interruptible. These tariffs allow WEPCO to interrupt service to these customers during times of peak demand, making capacity available to serve other customers. The customers taking service on these tariffs benefit by receiving a credit for any load that it is interrupted, and because peak demand can be reduced through interruptions, all other customers benefit by avoiding the need to build new capacity to serve peak demand.

Both WIEG and Charter proposed increases for the credits associated with non-firm service or interruptible service. WIEG argued that the interruptible credits had not been increased for some time even though firm demand charges have increased and that this has resulted in an increase in the differential between the firm demand charge and the interruptible demand charge. WIEG proposed increasing the interruptible credits by approximately

13 percent. Charter argued that WEPCO's rates are too high and that increasing the interruptible credits by approximately 19 percent would be appropriate. WEPCO's rate design maintained these credits at their current levels. WEPCO argued that interruptible customers need only make a short-term commitment to take interruptible service and that the present value of short-term capacity was very low. Commission staff presented a rate design that also maintained the interruptible credits at current levels. The Commission agrees with WEPCO and Commission staff and finds that it is reasonable to maintain the interruptible credits at current interruptible levels. The Commission finds that existing credits provide an adequate incentive for industrial customers to designate load as interruptible and strikes a reasonable balance between the low capacity prices in MISO and the cost of new entry. As WEPCO witness Mr. Rogers testified:

> In the past, the capacity credits for non-firm programs and rates were based on the marginal cost of generation capacity for a combustion turbine. In Dockets 05-UR-104 and 05-UR-106 we argued that the market price for capacity is well below this level, and the Commission agreed to close these non-firm options to new customers because of this situation. The market for contingency reserves, however, has developed in recent years, and the contingency reserve value can be applied to certain non-firm loads. The derivation of non-firm credits is shown in Ex.-WEPCO/WG-Rogers-11 Schedule 5 using both the cost of a combustion turbine and the cost of purchased capacity. The current non-firm credits are between these two derivations. For rate stability, we propose maintaining the current non-firm credits.

(Direct-WEPCO/WG-Rogers-43 and 44.)

Cancelling or Eliminating Residential Time-of-Use Rate Options

WEPCO proposed cancelling its Rg3 tariff and eliminating the Level 2 time-of-use (TOU) rate option in its Rg2 and Cg6 tariffs. WEPCO proposed maintaining its Level 1 TOU rate option in the Rg2 and Cg6 tariffs. WEPCO argued that the rates set in these tariffs send improper price signals because the current rate differential between on-peak and off-peak energy rates is greater than the actual on-peak and off-peak energy costs. Commission staff proposed an alternative that would lower the differential between on-peak and off-peak rates and keep these rate options available to existing customers.

According to WEPCO witness Mr. Rogers (Direct-WEPCO/WG-Rogers-37), the Rg3 and Rg2 Level 2 rates were established years ago[14] when WEPCO and the Commission were concerned with the availability of capacity to serve customers on-peak. These tariff options were intended to send a strong price signal to encourage customers to shift load away from peak hours. In recent years, WEPCO has constructed additional generation facilities and the availability of capacity has changed sufficiently to no longer justify continuation of these rates. The price for purchased capacity in 2015 and 2016 is projected to be only $5 per kW per year, which is relatively inexpensive compared to the cost of building new generation and reflects the availability of capacity. The average marginal cost for on-peak energy in 2015 and 2016 is projected to be roughly 1.4 times higher than the average marginal cost for off-peak energy, while the Level 2 on-peak rate differential is 5.2 times the off-peak energy. In contrast, the differential between on-peak and off-peak Level 1 rates proposed by WEPCO is 2.2. (Direct-WEPCO/WG-Rogers-37-38.)

The Commission finds it reasonable to accept WEPCO's proposal to cancel the Level 2 rate for the Rg2 and Cg6 customers and eliminate Rg3 rate all together. These rates have outlived any benefit they once provided and therefore should be closed. The Commission agrees with WEPCO that the Level 2 rate options send improper price signals and result in an

[14] *See Final Decision, Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC, both d/b/a We Energies, for Wisconsin Electric Power Company to Increase Its Electric, Natural Gas, and Steam Rates and For Wisconsin Gas LLC to Increase its Natural Gas Rates*, docket 6630-ER-2 (Jan. 17, 2008) (establishing Rg3) (PSC REF#: 88448); *See Findings of Fact and Interim Order, Submission of Wisconsin Electric Power Company of a Time Differential Rate Design and Application of Wisconsin Electric Power Company for Authority to Increase Its Electric Rates*, docket 6630-ER-5 (Jan. 5, 1978) (establishing Rg2).

unnecessary subsidy. The Commission further finds that it is reasonable that all customers currently taking service under Rg3 or the Rg2 and Cg6 Level 2 options be switched to an alternative tariff, either the level rate option in the appropriate Rg2 or Cg6 tariff, or the standard Rg1 or Cg1 flat rates, effective January 1, 2015.

Commissioner Callisto dissents. He would have kept the tariffs unchanged and open to new customers.

RTMP Contract Extensions

WEPCO proposed extending the RTMP contracts for customers taking service under an RTMP contract for an additional 3 years beyond the original 4-year term at each customer's current baseline. WEPCO argued that the additional 3 years would allow for a smoother transition off of the RTMP tariff for the current customers, rather than having these contracts expire after 4 years. Both Charter and WIEG supported extending RTMP contracts as proposed by WEPCO. WEPCO also proposed that Charter be allowed to transfer to the RTMP rider at its current Contract Services Tariff (CST) baseline. The CST is based on Charter Steel's historic usage levels during the 14-months period from October 2008 to November 2009, and was approved by the Commission's 2010 Final Decision in docket 6630-GF-132 pursuant to Wis. Stat. §196.192. Charter supported WEPCO's proposal. Commission staff noted that customers whose contracts will expire under the existing RTMP rider after 4 years may elect to enter into a new 4-year contract with a new baseline. Likewise, Commission staff observed that Charter is currently operating under a special contract rate that expires on December 31, 2015. At that time, Charter would be eligible to subscribe to the RTMP rider under its terms and conditions, including the establishment of an RTMP baseline.

WEPCO noted that the RTMP has stimulated economic development and load growth resulting in 1,200 new Wisconsin jobs and a 22 percent increase in load growth for RTMP customers. (Rebuttal-WEPCO/WG-Rogers-45.) Further, WEPCO indicated that the benefits RTMP provides to its subscribers and the state do not come at the expense of other customers. As articulated in the Commission's Final Decision in docket 6630-GF-134, no costs are born by non-participating customers because the tariff is structured so that the utility recovers all costs for load up to the participating customer's baseline. The Commission is not persuaded that free-ridership is an issue under this tariff. In addition, resetting the baseline could harm the current RTMP customers who have achieved growth over the last several years could also be a disincentive for them to grow further.

The Commission finds that it is reasonable to extend the RTMP contracts for existing customers for an additional 3 years and to allow Charter to transfer to the RTMP rider, at its current CST baseline, as proposed by WEPCO. The Commission agrees with WEPCO that resetting the baseline could harm the current RTMP customers who have achieved growth over the last several years. Continuing the RTMP contracts provides an additional incentive for these customers to add load, which ultimately benefits all of WEPCO's customers by spreading costs over a larger customer base once the RTMP contracts expire.

Commissioner Callisto dissents. He would have not extended the RTMP contracts at the current baseline nor would he have carried Charter's baseline over from the CST tariff.

New Rate and Tariff Proposals

The City of Milwaukee (City) proposed a new time-of-use street lighting tariff that is similar to the St1 tariff under which the City is currently served. Mr. Shambarger's testimony

(Direct–City of Milwaukee–Shambarger-3) initially raised the issue, which was responded to by WEPCO (Rebuttal-WEPCO/WG-Rogers-37r). Mr. Shambarger also provided a specific proposal (Surrebuttal-City of Milwaukee-Shambarger-1 to 2) in exhibit Ex.-City of Milwaukee-Shambarger-1) This new St2 tariff would have the same rates as the St1 rate, but it would establish a different 12-hour on-peak period that would result in lower energy costs for the City in operating its street lighting system. WEPCO supported the creation of this new tariff and proposed that any incremental revenue loss due to this change be shifted to other street lighting customers. The Commission finds it is reasonable to create and implement a new St2 tariff, as proposed by the City. The Commission agrees that revenue allocated to the street lighting class should, in general, remain within this class. However, the Commission finds that there is insufficient information in this record to compute the revenue loss by shifting the City from the St1 to the St2 tariff. As a result, it is unreasonable to reallocate any lost revenues to other street lighting customers in this proceeding.

Charter proposed a new tariff for customers who take service directly from the high voltage transmission system. (Direct-Charter Steel, Inc.-Vock-6, Initial Brief, 1 to 7, and Reply Brief, 2.) Charter argued that these customers more closely resemble wholesale customers, and that the rates paid by these customers should be based on WEPCO's current wholesale tariffs approved by FERC. These tariffs include a monthly capacity charge, an energy charge, transmission costs, and other retail charges. According to Charter, this would provide a more competitive rate for electric power for Wisconsin manufacturers. It is unreasonable to establish a new tariff for high-voltage transmission-only customers at this time. The Commission understands Charter's concerns about economic competitiveness, but finds that this rate proposal was not fully developed in the record and as a result, there is insufficient evidence to make this change.

Rate and Rule Tariff Language Changes

WEPCO proposed numerous minor changes to its electric rules and regulation tariffs as shown in exhibits Exs.-WEPCO/WG-Rogers-17 through 19. WEPCO also proposed changes to its electric extension embedded allowances. There were no objections to these changes. The Commission finds that the electric rate and rule tariff language changes and the changes to the electric extension embedded allowances proposed by WEPCO are reasonable.

Distributed Generation Tariffs

Overview of Proposed Changes

WEPCO filed a proposal to restructure its Distributed Generation (DG) tariffs for customers who own or operate electric generating facilities at their premises and that are used to offset some or all of their power requirements. Under WEPCO's proposal, its current CGS-1, CGS-2, CGS-6, CGS-7, and CGS-8 tariffs would be cancelled effective December 31, 2015. Any customers taking service under these tariffs would be migrated to one of four new DG tariffs, COGS-DS-FP (direct sale fixed price), COGS-DS-VP (direct sale variable price), COGS-NM (net metering), and COGS-NP (non-purchase). Customers enrolled in the CGS-4, CGS-5, or CGS-PV tariffs would continue to take service under their respective tariff until the expiration date of their current contract, at which time these customers would be migrated to the applicable tariff. The CGS-3 would remain unchanged. In its initial brief, WEPCO indicated that it was willing to modify its original proposal to allow CGS-1, CGS-2, CGS-6, and CGS-8 customers who applied for service under those tariffs as of October 7, 2014, to remain under these tariffs until December 31, 2024.

The proposed COGS-DS-FP and COGS-DS-VP tariffs would replace the current CGS-1 tariff as WEPCO's standard offer rate for DG customers who do not qualify for the COGS-NM service. Under the proposed COGS-DS tariffs, customers would be credited for energy sold to WEPCO at a rate based on LMP in the MISO market. The energy credit rates for COGS-DS-FP would be based on averages of the test year LMP forecast, while COGS-DS-VP customer would be credited at rates based on actual day-ahead MISO LMP at WEPCO's load zone. WEPCO proposed that the energy credit rates for both COGS-DS tariffs would include a credit for avoided transmission cost.

The proposed COGS-NM tariff would replace the CGS-2, CGS-6, CGS-7 and CGS-8 net metering service tariffs. COGS-NM would be available to customers with generating systems up to 300 kW in capacity at a single customer premise. The COGS-NM tariff would allow customers to net their generation against their consumption on a monthly basis, with any net surplus generated energy credited to the customer at a rate based on LMP, plus avoided transmission cost.

The proposed COGS-NP tariff would establish a new type of service intended for customers who have indicated excess energy but who do not wish to sell energy to WEPCO. Presently, some WEPCO customers have filed a letter of acknowledgement with WEPCO regarding their generating systems indicating that they agree to not receive credit for any energy delivered to WEPCO. COGS-NP would be an optional tariff for these customers, as well as for other DG customers who expect that their generation will rarely, if ever, exceed their consumption.

The COGS tariffs proposed by WEPCO also include an assortment of new charges for DG customers. COGS-DS and COGS-NM customers would be billed a monthly facilities charge based on each customer's base consumption tariff, with small, medium, and large customers being assessed different facilities charge rates. These COGS facilities fees are in addition to the facilities charges that are billed as part of the customer's base consumption rate. WEPCO also proposed a new demand charge for COGS-NM and COGS-NP customers. The demand charge would be a per-kW charge billed according to the nameplate capacity of the customer's generating system, with the rate varying depending on the customer's size and whether the customer's generation equipment is intermittent.

In proposing this rate restructuring for DG, WEPCO argued that its current DG tariff structure was inadequate to allow it to equitably recover its fixed costs. WEPCO argued that customers with their own generation contribute less than their equitable share to WEPCO's fixed costs, including production and transmission costs, than a customer with similar gross energy consumption patterns without DG because some of these fixed costs are currently recovered through the energy charges. WEPCO argued that this produces an unreasonable intra-class cross-subsidy borne by customers who do not own DG systems. WEPCO also argued that while net metering customers and direct-sale parallel generation customers rely on WEPCO's distribution system in order to deliver their generated electricity to other customers, the revenue collected from these customers' through their base consumption tariff rates is insufficient to allow for full recovery of what WEPCO identifies as fixed distribution, administrative, and common costs. WEPCO argued that the proposed capacity demand charge would allow it to properly recover the fixed production and transmission costs that it must incur in order maintain sufficient capacity to serve COGS-NM and COGS-NP customers during periods when their generating systems are not operating. Similarly, the proposed COGS facilities charges would allow WEPCO to recover an equitable amount of the fixed costs from the COGS-NM and COGS-DS customers.

Finally, WEPCO proposed a requirement that customers taking service under the new COGS tariffs own their own generating systems. WEPCO cited a letter from the Division Administrator for Gas and Energy, as well as a letter from the Commission's Chief Legal Counsel, in support of its proposal, arguing that this requirement would bring the its tariff in line with what it believes is the Commission's stated position regarding third-party ownership of DG systems.

Intervenors Charter, ELPC, MMSD, RENEW, Sunvest Solar, Inc. (Sunvest), TASC, and Commission staff provided testimony regarding WEPCO's proposed restructuring of its DG tariffs. ELPC, RENEW, Sunvest, and TASC disagreed with WEPCO's initial position that WEPCO's DG tariffs required restructuring. ELPC, MMSD, RENEW, Sunvest, and TASC, raised concerns that WEPCO had neither performed a sufficient analysis to support its claims of cross-subsidization, nor provided sufficient evidence to support the charges proposed. Charter expressed similar concerns regarding the capacity demand charge as it is applied to the COGS-NP service. Several intervenors suggested that a separate Commission investigation or a stakeholder collaborative process would be appropriate in order to more fully develop these issues for Commission consideration.

Closure of CGS-1, CGS-2, CGS-6, and CGS-8 Tariffs

The Commission accepts, as modified by this Final Decision, WEPCO's request to close CGS-1, CGS-2, CGS-6, CGS-7, and CGS-8 tariffs and to replace these tariffs with new tariff offerings (COGS-DS-FP, COGS-DS-VP, COGS-NM and COGS-NP). These new tariffs are fair, both to those with distributed generation and to those without. This restructuring moves WEPCO a step closer to more appropriately aligning costs and fairly compensating customers that generate a portion of their electricity needs without increasing costs to those who cannot or do not do so. WEPCO's suggested changes follow the guidance the Commission previously gave in its decision in docket 5-GF-233 wherein the Commission stated: "Current tariffs may need to be re-examined to ensure distributed generation buyback rates fairly reflect costs and benefits associated with distributed generation, and to ensure that utility rate structures appropriately recover the costs associated with providing utility service to customers with distributed generation." [15] The Commission encouraged utilities to consider restructuring their DG rates in a rate case, and that is what WEPCO has done here.

Some intervenors advocated for maintaining higher payments to customers with their own generation citing purported societal benefits of distributed generation. The Commission finds that the record in this case as to any such benefits is insufficient. Further, as a matter of public policy, the Commission declines to assign such benefits for distributed generation in rates as such an examination is not done for other generation resources. As discussed earlier in this Final Decision, when this Commission decides to enact reforms to restructure rate design and

[15] *Petition to Open a Rulemaking Docket to Consider Amending Wis. Admin. Code ch. PSC 119 and Wis. Admin. Code § PSC 113.10 Related to Distributed Resources Interconnection Rules*, docket 5-GF-233, Order (PSC REF#: 193575) (Nov. 15, 2013).

cancel, revise or approve new tariffs, it exercises a legislative function and is given wide discretion. The same policies articulated by this Commission in approving WEPCO's facilities charges—namely sending more appropriate price signals, better aligning rates with costs, and assigning costs more equitably to those who cause the costs—support the Commission's decision to accept, with some modifications, WEPCO's proposed new tariffs.

Some intervenors also argued that making the proposed tariff changes now is premature and not necessary because DG only makes up a small fraction of WEPCO's current system. However, it is precisely for that reason that it is reasonable to restructure WEPCO's DG tariff offerings now. The Commission finds, based upon the facts and as a matter of public policy, that there are utility fixed costs that are not being borne by DG customers and a change should be made now before those costs grow with increased adoption of DG. The use of distributed generation is expected to continue to increase and it is important for those making such investments to understand the real costs and benefits of those investments and make informed choices.

Subject to the conditions described below, the Commission finds that it is reasonable to authorize the tariff changes requested by WEPCO, as this will move WEPCO in the direction of better aligning its rates with its costs. To that end, and as modified by this Final Decision, it is reasonable to authorize WEPCO to close the CGS-1, CGS-2, CGS-6, CGS-7, and CGS-8 tariffs effective December 31, 2015, and place the proposed COGS-DS-FP, COGS-DS-VP, COGS-NM, and COGS-NP tariffs, as modified below, into effect on January 1, 2016.

Commissioner Callisto dissents and writes separately.

Approved COGS-NP, COGS-NM and COGS-DS Tariffs

The Commission finds that the proposed buyback rates in the COGS-NP, COGS-DS, and COGS-NM tariffs, which are based upon LMP plus the avoided cost of transmission, are reasonable. Such LMP-based buyback rates fairly reflect what costs WEPCO avoids when it purchases energy from a DG customer instead of purchasing energy on the market. (Direct-WEPCO/WG-Rogers-59-60.). As WEPCO witness Mr. Rogers succinctly stated:

> Avoided cost is the cost the Company avoids by purchasing its next unit of energy from the net metering customer. If the Company did not purchase that unit from the net metering customer, it would purchase it from the MISO market, and the cost would be equal to LMP. Therefore, the Company's avoided cost for that unit is equal to LMP.

(Rebuttal-WEPCO/WG-Rogers-15r.) To set the buyback rate at something higher than avoided cost for customer-generated energy would set an inappropriate price signal and would be unfair to customers without their own generation. Placing an inflated value on the value of the customer-generated energy over-incentivizes investment in DG. (Rebuttal-WEPCO/WG-Brown-10-11.) Paying more than the avoided cost is unfair because it artificially inflates the price and that higher price is paid by other customers.

Further, using LMP as a proxy for the utility's avoided costs in DG tariffs is consistent with the value that the Commission has assigned to this energy in other proceedings and has been affirmed as reasonable upon judicial review.[16] The Commission also observes that it has consistently used LMP as the best proxy for market price in the non-DG context and finds that

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[16] *See, e.g., 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)(Dec. 21, 2012); *RENEW Wisconsin v. Public Service Commission of Wisconsin et al.*, Case No. 13-CV-851 (Dane County Cir. Ct.) (May 13, 2014).. *See, e.g., also Application of Wisconsin Public Serv. Corporation for Authority to Adjust Electric and Natural Gas Rates,* docket 6690-UR-120 , Final Decision (PSC REF#: 143675)(Jan. 13, 2011).

no compelling case has been made that DG should be treated differently.[17] The Commission is not persuaded that the "value of solar" approach advocated by RENEW and TASC is a more accurate proxy for avoided costs than LMP. Additionally, the Commission concludes that to include some of the costs that RENEW and TASC[18] contend should be included in avoided costs strays from what the law suggests this Commission to consider. *See* 18 C.F.R. § 292.304(e).

The Commission concludes that monthly net-metering under the COGS-NM tariff is also reasonable. Energy has different values depending upon when it is produced. Monthly net metering more accurately and more fairly values distributed generation by crediting on-peak use at the on-peak rates and crediting summer generation at typically higher summer-based rates. (Rebuttal-WEPCO/WG-Rogers-21r.) This Commission approval of the use of net monthly billing in the COGC-NM tariff is consistent with the Commission's policy determination in docket 6690-UR-122.

With regard to the proposed demand charges based on the installed capacity of generation for customers on the new COGS-NM and COGS-NP, the Commission finds that the demand charges are reasonable and will allow WEPCO a reasonable opportunity recover standby generation and distribution costs that are not recovered by the facilities charge of the underlying rate (Applicants' Initial Brief, p19-20; Direct-WEPCO/WG-Rogers-56-57). Based upon the information currently available, it is reasonable to establish the demand charge based on the name-plate capacity of the generating equipment. However, the Commission notes that there are

[17] *See, e.g., Northern States Power Company-Wisconsin*, docket 4220-UR-117, Final Decision (PSC REF#: 157438)(Dec. 22, 2011); *Madison Gas and Electric Company*, docket 3270-UR-118, Final Decision (PSC REF#: 177918)(Dec. 14, 2012); *Wisconsin Power and Light Company*, docket 6680-FR-105, Final Decision (PSC REF#: 177617)(Dec. 7, 2012).
[18] *See, e.g.,* Direct-Renew-Vickerman-25; Direct-TASC-Hornby-12r.

some questions regarding how closely the name-plate capacity reflects actual demand. To inform consideration of this issue in future cases, the Commission conditions its approval of the demand charge on the following. First, the Commission finds it reasonable to direct WEPCO to install meters capable of measuring the actual output capacity of generating systems newly-enrolled under COGS-NM and COGS-NP on an interval basis. The cost of this metering shall be borne by WEPCO. In WEPCO's next full rate proceeding, the Commission will re-examine whether the nameplate capacity of such generating equipment is a reasonable proxy for actual demand and if installation of demand meters will be an ongoing requirement, who should bear the costs of such metering. Second, at the end of 2016, a true-up shall be performed wherein the metered data shall be used to compare the customer's actual monthly maximum generation capacity with the rated nameplate capacity of the same system. If the customer's actual monthly maximum generation capacity is lower than the rated nameplate capacity, a credit shall be issued to the customer reflecting the difference for those billing periods. If the customer's actual monthly maximum generation capacity is greater than the rated nameplate capacity, a surcharge shall be issued to the customer reflecting the difference for those billing periods. Finally, WEPCO shall present the data collected through this metering in its next full rate proceeding so that the Commission may evaluate whether the COGS capacity demand charges, and the basis for determining the billing units for those charges, are appropriate or require modification. Should WEPCO not file for a 2017 test year rate case, the aforementioned true-up shall be performed annually until WEPCO's next full rate proceeding.

With regard to WEPCO's proposed COGS-DS tariff, the Commission finds that this tariff is reasonable and is consistent with the parallel generation rates authorized for other utilities in the state. However, the Commission declines to include a capacity credit based upon the MISO capacity market. While the Commission has approved a capacity credit for other utilities, the Commission concludes that the record in this proceeding is insufficient to determine the appropriate value for capacity that would be the basis for any such credit.

Commission Callisto dissents and writes separately.

Grandfathering of Existing DG Customers

The Commission finds it reasonable to provide for a grandfathering treatment for existing customers, in recognition of the customers' good faith expectations regarding the pay-back period for their investment in these systems, under the existing tariff structure. As proposed by WEPCO, CGS-1, CGS-2, CGS-6, and CGS-8 customers who applied for service under these tariffs as of October 7, 2014, shall be allowed to remain under these tariffs until December 31, 2024. Customers who have applied for service under any of these tariffs after October 7, 2014, will be transferred to the appropriate COGS tariff effective January 1, 2016.

Commissioner Nowak dissents.

Revenue from COGS Tariffs

WEPCO did not provide any estimate of the revenue that would be generated by its proposed COGS charges. While the Commission recognizes that this revenue may be immaterial for the 2016 test year, given the uncertainty surrounding the authorized charges, the Commission finds it reasonable to require WEPCO to defer any revenue collected from the new COGS charges until WEPCO's next full rate proceeding.

Waiver of Wis. Admin. Code § PSC 113.0406(5)

Alongside its proposed COGS tariffs, WEPCO requested a waiver of Wis. Admin. Code § PSC 113.0406(5) for the new COGS-DS-FP, COGS-DS-VP, and COGS-NM tariffs. Wisconsin Admin. Code § PSC 113.0406(5) governs the availability of budget billing for utility service. This request was not contested by any party and the Commission finds merit in the WEPCO's argument that budget billing distorts the price signals for DG customers. (Direct-WEPCO/WG-Rogers-66.) WEPCO's specified request for a waiver of Wis. Admin. Code § PSC 113.0406(5) is reasonable and granted.

Standby Service Tariffs

WEPCO filed a request to institute a new Cg4 standby service for secondary customers to supplement its existing Cp4 standby service. As part of that request, WEPCO requested that standby service be made mandatory for DG customers with generating systems of 300 kW or greater who supply 35 percent or more of their on-site load.

WEPCO provided testimony arguing that the expansion of standby service to secondary customers, along with the proposed mandatory service requirements and minimum reserved capacity levels are necessary to allow the utility to recover fixed production capacity costs that it believes it must incur in order to have sufficient capacity in the event that the customer's generation is unavailable. (Direct-WEPCO/WG-Rogers-60-62.) MMSD and Commission staff provided testimony evaluating WEPCO's standby service proposal. Neither MMSD nor Commission staff opposed WEPCO's proposal to institute the new Cg4 standby service, with Commission staff indicating that the expansion of standby service to secondary customers may provide a valuable option for customers. (Direct-PSC-Singletary-35.) However, both MMSD and Commission staff did express concern regarding WEPCO's proposal to mandate standby service for certain customers. In particular, MMSD indicated concern that WEPCO had not provided sufficient evidence to support making standby service mandatory, and had also not performed any kind of customer impact or revenue analysis. (Rebuttal-MMSD-Cicchetti-3-5; Direct-MMSD-Krill-8r-9r; Surrebuttal-PSC-Singletary-9-10.) Commission staff suggested at this time that standby service could be provided solely as an option for customers who self-supply but would like to reserve stand-by service to avoid high demand charges during periods when their generation is offline. (Direct-PSC-Singletary-36.)

The Commission finds that WEPCO's proposed Cg4 and Cp4 standby service tariffs are unreasonable. The Commission concludes that there is insufficient evidence in the record to support WEPCO's request that standby service be made mandatory for DG customers with generating systems of 300 kW or greater who supply 35 percent or more of their on-site load. The Commission also declines to approve the new Cg4 standby service as an option as suggested by MMSD and Commission staff. Further, while the record suggests the proposal would generate at least $1.0 million to $1.5 million in additional revenue in in 2016, WEPCO did not discuss how those revenues are to be accounted for in its total revenue requirement or any identification of what unrecovered costs these revenues would offset. Therefore, the Commission concludes that, at this time and based upon the record presented in this proceeding, the proposed Cg4 and Cp4 tariffs are not reasonable and are therefore not approved.

That being said, the Commission finds some merit in in WEPCO's arguments regarding standby service, and it would like to see these concepts further developed in a future rate case proceeding. The Commission directs that WEPCO develop a standby rate proposal in close cooperation with affected customers, and present that rate proposal in its next full rate case.

Third-Party Ownership

WEPCO is correct in stating that the Division Administrator for Gas and Energy and the Commission's Chief Legal Counsel both authored letters containing staff positions on third-party generating systems. (Ex.-TASC-Friedman-4r.) However, not only are the statements and conclusions contained in these letters fact specific, as stated in the letter from the Commission's Chief Legal Counsel, the positions espoused therein represent a staff opinion only and do no not constitute a formal determination by this Commission. This Commission believes that the clarification of Wisconsin statutes regarding the status of third-party ownership of DG is more appropriately within the purview of the Wisconsin Legislature. Consequently, the Commission finds it reasonable to continue to evaluate whether third-party owned DG systems comply with Wisconsin statues and administrative code on a case-by-case basis. As such, WEPCO's request for a blanket prohibition on third-party owned DG is not authorized.[19]

Stakeholder Collaborative

Finally, while the Commission recognizes that DG and DG rate issues are an increasingly contested issue, the evidence in this proceeding on both sides of all of the issues is extensive and there is no need to open a separate investigation into DG at this time. Similarly, there is no need to direct that a stakeholder collaborative be convened to further develop and explore DG issues. In fact, this Commission finds that the record in this proceeding contains a robust exploration of the issues, and provides a sufficient basis upon which to base the Commission's decisions. As

[19] Note that WEPCO's use of "Customer Owned Generation," or COG, in a tariff name does not have any legal significance and does not impact on the determination of whether third-party ownership of DG is authorized or not.

such it is not reasonable at this time to open a separate investigation, or direct that a stakeholder collaborative process be convened, in order to examine DG rate design issues.

Commissioner Callisto dissents and writes separately.

Steam Revenue Allocation and Rate Design

Both WEPCO and Commission staff proposed steam revenue allocations and rate designs. They are similar except for the impact of the fuel forecast on the level of the proposed increases. Subsequent to the hearing, the revenue allocation changed significantly as a result of the authorized fuel cost update and the pass-through of these fuel costs to WEPCO's steam operations. The overall steam increase is 4.2 percent for 2015. The revenue allocation is a 7.2 percent increase for the VA Steam operation and a 2.0 percent increase for the MC Steam operation. The Commission finds that the steam revenue allocation and rate design proposed by the Commission staff is reasonable.

Steam Rate and Rule Tariff Changes

WEPCO proposed changes to its steam extension embedded allowances and steam tariff language shown in exhibits Ex.-WEPCO/WG-Rogers-4 and 5, which were unopposed. The Commission finds that the changes to the steam extension embedded allowances and the steam rules proposed by WEPCO are reasonable.

Natural Gas COSS and Rates

Natural Gas COSS

We Energies prepared customer-oriented COSS and Commission staff prepared customer-oriented studies (COSS A) and commodity-oriented studies (COSS B) for WG and did not prepare COSS for WE-GO. We Energies' and Commission staff's 2015 and 2016 WG COSS A allocate costs based on number of customers, average usage and peak demand.

Commission staff's 2015 and 2016 WG COSS B allocate 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.

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. The Commission finds that this continues to be a reasonable approach to setting natural gas rates.

Natural Gas Rates

Revenue Recovery Adequacy of Service Class Rates

The gas rate design, proposed by Commission staff, was not opposed by any party and the Commission finds it reasonable.[20]

Overall, the rates authorized for WE-GO in Appendix D of this Final Decision will provide an 8.60 percent rate of return on the average gas net investment rate base. This represents a decrease of 6.56 percent in margin rates and a 2.38 percent in total natural gas sales revenues. Margin rates exclude natural gas costs from the increase calculations.

Authorized rates for WE-GO as set forth in Appendix D 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 D.

[20] WE-GO and WG's proposed 61 cent increase to the gas fixed charge component for residential gas services was not, unlike the electric fixed charge increase, contested by any party and is accepted by the Commission.

Appendix D also shows some typical WE-GO natural gas bills for residential service, comparing existing rates with new rates including the cost of natural gas.

Overall, the rates authorized for WG Appendix E of this Final Decision will provide an 8.36 percent rate of return on the average gas net investment rate bases for the test years 2015 and 2016. For test year 2015, this represents an increase of 7.01 percent in margin rates and a 2.62 percent in total natural gas sales revenues. For test year 2016, there would be an additional increase of 8.19 percent in margin rates and an additional 3.21 percent in total natural gas sales revenues.

Authorized WG rates for 2015 and 2016 as set forth in Appendix E 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 E.

The natural gas COSS results in a relatively wide range of changes in the charges to the various WE-GO and WG 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 E also shows some typical WG natural gas bills for residential service for 2015 and 2016, comparing existing rates with 2015 rates including the cost of natural gas and comparing 2015 rates with 2016 rates.

Natural Gas Tariff Issues

During post-hearing briefing, Charter Steel introduced a request to allow the electronic aggregation of separately-metered gas loads. As this issue was not presented in the record, it is not appropriate to discuss or decide it in this Final Decision. The request is not authorized. The request, however, may be worthy of further discussion and the Commission encourages Charter and WG to continue these discussions and consider addressing this issue in the next rate case.

WE-GO and WG proposed to eliminate the NGV Sales Service NGV Classes 1, 2, and 3. Additionally, WE-GO and WG proposed several modifications to the Rely-A-Bill Services tariff. Neither proposal was opposed by any party. The Commission finds it reasonable to approve both proposals.

Effective Date

The Commission finds it reasonable for the authorized electric, steam, 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 the utilities 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). 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 utilities 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 January 1, 2015, provided that the utilities file these rates and tariff provisions with the Commission and makes them available to the public 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 on the date they are filed with the Commission and made available to the public.

3. WEPCO and WG may revise its existing rates and tariff provisions for electric, natural gas, and steam utility service, substituting the rate increases and tariff provisions that restrict the terms of service, as shown in Appendices B, C, D and E, 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. WEPCO and WG shall file these rate decreases and tariff provisions with the Commission and make them available to the public by that date.

5. By January 1, 2015, WEPCO and WG shall revise its existing rates and tariff provisions for electric, natural gas, and steam utility service, substituting the rate decreases and tariff provisions that expand the terms of service, as shown in Appendices B, C, and D 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. WEPCO and WG shall prepare bill messages that properly identify the rates authorized in this Final Decision. WEPCO and WG 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. WEPCO and WG shall file tariffs consistent with this Final Decision.

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

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

10. WEPCO is authorized to waive Order Point 34 from the Final Decision in docket 5-UR-106 for an ERGS unit while that unit is test-burning PRB coal during 2015.

11. WEPCO shall utilize escrow accounting treatment for the 2015 PIPP SSR revenue payments and shall record Wisconsin retail revenues of $90.7 million for this escrow in 2015 with the carrying costs on WEPCO's escrowed 2015 SSR revenue accruing at WEPCO's authorized weighted cost of capital.

12. WEPCO shall continue escrow accounting treatment of the Treasury Grant credits and shall inform the Commission of any changes in the Treasury Grant credits on an annual basis until such time that the credits are final.

13. WEPCO shall continue escrow accounting treatment of the Section 199 Domestic Production Tax Deduction.

14. WEPCO shall establish an escrow account for its Agriculture Service Program beginning in 2015 and shall record $1,317,000 of expense for this escrow annually until the Commission authorizes a different amount to be recorded.

15. WEPCO shall amortize $3,013,000 of escrowed uncollectible accounts expense annually for WEPCO's electric utility on a Wisconsin retail basis for 2015 and 2016 or until the Commission authorizes a different amortization expense to be recorded.

16. WEPCO shall amortize a negative amount of $1,900,000 of escrowed uncollectible accounts expense annually for WE-GO for 2015 and 2016 or until the Commission authorizes a different amortization expense to be recorded.

17. WG shall amortize a negative amount of $10,760,000 of escrowed uncollectible accounts expense annually for 2015 and 2016 or until the Commission authorizes a different amortization expense to be recorded.

18. WEPCO electric shall record $57,903,000 of annual conservation escrow expense, which consists of $46,604,000 of estimated expenditures plus $11,299,000 of amortization of overspent amounts.

19. WE-GO shall record $7,883,000 of annual conservation escrow expense, which consists of $8,054,000 of estimated expenditures less a negative $171,000 of amortization of underspent amounts.

20. WG shall record $10,323,000 of annual conservation escrow expense, which consists of $10,692,000 of estimated expenditures less a negative $369,000 of amortization of underspent amounts.

21. The conservation escrow expense amounts shall continue to be recorded annually until a new rate order is issued by the Commission authorizing different amounts to be recorded.

22. Unless discussed separately in this Final Decision, the annual expense amounts itemized in exhibit Ex.-WEPCO/WG-Ackerman-4, Schedule 1, shall be recorded for all items

listed for 2015 and 2016 or until the Commission authorizes a different amortization expense to be recorded.

23. WEPCO shall maintain a long-term range of 48.5 percent to 53.5 percent for its common equity ratio, on a financial basis.

24. WG shall maintain a long-term range of 47.0 percent to 52.0 percent for its common equity ratio, on a financial basis.

25. WEPCO and WG shall submit ten-year financial forecasts in their next rate proceedings.

26. WEPCO shall not pay dividends in excess of the amount forecasted in this proceeding if such dividends cause the average annual common equity ratio, on a financial basis, to fall below the test-year authorized level of 51.00 percent. WEPCO shall not pay a special dividend in excess of the forecasted dividends at the end of the year unless the additional payment does not reduce the average annual common equity ratio, on a financial basis, below the forecasted level of 51.00 percent.

27. WG shall not pay additional dividends above those estimates deemed reasonable in this proceeding without prior Commission approval, if, after the payment of such dividends, the actual average common equity ratio, on a financial basis, would be below the test-year authorized level of 49.50 percent.

28. WEPCO 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, the minimum annual lease and purchased power agreement obligations; the method of calculation along with the calculated

amount of the debt equivalent; and supporting documentation, including all reports, correspondence and any other justification that clearly establish Standard & Poor's and other major credit rating agencies' determination of the off-balance sheet debt equivalent, to the extent available, and publicly available documentation if Standard & Poor's and other credit rating agencies' documentation is not available.

29. All authorized amortization shall begin on January 1, 2015, or as of the effective date of this Final Decision, whichever is later.

30. WEPCO shall to work with WIEG, other interested stakeholders, and Commission staff to evaluate its electric cost of service with respect to the seasonality of its costs, and to develop and submit a seasonally differentiated electric rate design proposal in its next base rate proceeding.

31. WEPCO shall install meters capable of measuring the actual output capacity of generating systems newly-enrolled under COGS-NM and COGS-NP on an interval basis. The cost of this metering shall be borne by WEPCO. In WEPCO's next full rate proceeding, the Commission will re-examine whether the nameplate capacity of such generating equipment is a reasonable proxy for actual demand and if installation of demand meters will be an ongoing requirement, who should bear the costs of such metering.

32. WEPCO shall perform a true up at the end of 2016 wherein the metered monthly maximum generation capacity of customers enrolled under COGS-NM or COGS-NP shall be compared to the rated nameplate capacity of the same system. If the customer's actual monthly maximum generation capacity is lower than the rated nameplate capacity, a credit shall be issued to the customer reflecting the difference for those billing periods. If the customer's actual

monthly maximum generation capacity is greater than the rated nameplate capacity, a surcharge shall be issued to the customer reflecting the difference for those billing periods. Should WEPCO not file for a 2017 test-year rate case, the aforementioned true-up shall be performed annually until WEPCO's next full rate proceeding.

33. WEPCO shall present the data collected through the metering of COGS-NM and COGS-NP customers in its next full rate proceeding so that the Commission may evaluate whether the COGS capacity demand charges, and the basis for determining the billing units for those charges, are appropriate or require modification.

34. WEPCO shall develop a standby rate proposal in close cooperation with any affected customers, and present that rate proposal in WEPCO's next full rate proceeding.

35. WEPCO shall defer the revenue collected through the newly authorized COGS tariffs until its next full rate proceeding.

36. WE-GO and WG are authorized to eliminate tariffs providing service NGV Sales Service and to provide such service pursuant to rates serving similar service rate classes.

37. Jurisdiction is retained.

Dissent

Commissioner Callisto dissents and writes separately.

Dated at Madison, Wisconsin, this 23rd day of December, 2014.

By the Commission:

Sandra J Paske

Sandra J. Paske
Secretary to the Commission

SJP:MJK:cmk:DL: 00951429

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.[21] 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

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

Docket 6690-UR-122

APPENDIX A

PUBLIC SERVICE COMMISSION OF WISCONSIN

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 — 5-UR-107

CONTACT LIST FOR SERVICE BY PARTIES

THE ALLIANCE FOR SOLAR CHOICE
Tim Lindl
Keyes, Fox & Wiedman LLP
436 14th Street, Ste 1305
Oakland, CA 94612

AURORA SINAI MEDICAL CENTER
Jane Appleby
Associate General Counsel, Litigation
750 West Virigina Street
PO Box 341880
Milwaukee, WI 53215-1880
Ph. 414-299-1765
Jane.appleby@aurora.org

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

CITY OF MILWAUKEE
Thomas D. Miller
Assistant City Attorney
200 East Wells St., Room 800
Milwaukee, WI 53202
tmiller@milwaukee.gov

Docket: 5-UR-107

CHARTER STEEL
Robert Dietz
1558 Cold Springs Road
Saukville, WI 53080
Ph. 262-268-2312
dietzb@chartersteel.com

> Additional contact:
> Daniel J. Eastman, Esq.
> Titus Group, Inc.
> 1200 Mayfair Road
> Milwaukee, WI 53226
> PH. 414-978-4732
> Dan.Eastman@titus-us.com

CLEAN WISCONSIN
Katie Nekola
634 Main St. Ste 300
Madison WI 53703-2687
Ph.: (608) 251-7020 x14
knekola@cleanwisconsin.org

CONSTELLATION NEWENERGY-GAS DIVISION, LLC
Darcy Fabrizius
N21 W23340 Ridgeview Parkway
Waukesha, WI 53188
Ph. 262-506-6600
Darcy.fabrizius@constellation.com

ENVIRONMENTAL LAW & POLICY CENTER
Robert Kelter
Bradley D. Klein
Howard A. Learner
Stephanie K. Chase
222 S. Hamilton Street, Suite 14
Madison, WI 53703
rkelter@elpc.org;bklein@elpc.org; hlearner@elpc.org; schase@elpc.org

FRIENDS OF THE FUND FOR LAKE MICHIGAN
Bradley D. Jackson
Foley & Lardner, LLP
150 East Gilman Street
Madison, WI 53703-1481
Ph. 608-258-4262
bjackson@foley.com; bpotts@foley.com

Docket: 5-UR-107

IUOE LOCAL 420
Paul Zakszewski
1140 W. Anderson Ct.
Oak Creek, WI 53154
Zakpk7679@sbcglobal.net

MADISON GAS AND ELECTRIC COMPANY
Edwin J. Hughes
Bryan Kleinmaier
Stafford Rosenbaum LLP
222 West Washington Avenue, Suite 900
Madison, WI 53701-1784
Ph. 608-259-2658
ehughes@staffordlaw.com; bkleinmaier@staffordlaw.com

MILWAUKEE METROPOLITAN SEWERAGE DISTRICT
Thomas Mullooly
Foley & Lardner LLP
777 E. Wisconsin Ave.
Milwaukee, WI 53202
Ph. 414-297-5566
tmullooly@foley.com santhony@mmsd.com

MARQUETTE UNIVERSITY
Douglas O. Smith
Associate General Counsel
Zilber Hall 205
PO Box 1881
Milwaukee, WI 53201-1881
Ph. 414-288-6486
Douglas.smith@marquette.edu

MICHAEL R. CHIAL, PH.D
W7208 State Road 106
Fort Atkinson, WI 53538
PH. 920-563-0393
mrchial@wisc.edu

RENEW WISCONSIN
Bradley D. Klein
Stephanie K. Chase
222 S. Hamilton Street, Suite 14
Madison, WI 53703
bklein@elpc.org; schase@elpc.org

Docket: 5-UR-107

SUNVEST SOLAR, INC.
Susan M. Crawford
Jeffrey L. Vercauteren
Cullen, Weston, Pines & Bach, LLP
122 West Washington Avenue, Suite 900
Madison, WI 53703
Ph. 608-251-0101
crawford@cwpb.com; vercauteren@cwpb.com

WISCONSIN ELECTRIC POWER COMPANY & WISCONSIN GAS LLC
Brian D. Winters
Joe Wilson
Quarles & Brady LLP
411 East Wisconsin Avenue, Suite 2350
Milwaukee, WI 53202-4426
Brian.winters@Quarles.com; joe.wilson@quarles.com

Additional contacts:
Jim Schubilske
Vickie Nugent
Catherine Phillips
231 W. Michigan Street
Milwaukee, WI 53203
Ph. 414-221-2569 (Nugent)
Vickie.Nugent@we-energies.com; Catherine.Phillips@we-energies.com

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

Additional contact:
Todd Stuart
Executive Director
Wisconsin Industrial Energy Group, Inc.
10 E. Doty Street, Ste. 800
Madison, WI 53703
Phone: 608.441.5740
Fax: 608.441.5741
tstuart@wieg.org

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

WPPI ENERGY
Thomas S. Hanrahan
General Counsel
1425 Corporate Center Drive
Sun Prairie, WI 53590
Ph. 608-834-4500
thanrahan@wppienergy.org

PUBLIC SERVICE COMMISSION OF WISCONSIN
(Not a party, but must be served)
610 North Whitney Way
P.O. Box 7854
Madison, WI 53707-7854
Please file documents using the Electronic Regulatory Filing (ERF) system which may be accessed through the PSC website: https://psc.wi.gov.

John Lorence
Candice Spanjar
610 North Whitney Way
PO Box 7854
Madison, WI 53707-7854
john.lorence@wisconsin.gov; candice.spanjar@wisconsin.gov

Wisconsin Electric Power Company

Electric Revenue Summary

for Test Year ending December 31, 2015 & for 2016

Rate Schedules & Customer Classes	Revenue in TY2015 with Present Rates	Revenue in 2015 with Authorized Rates	Change 2015 Over Current	Revenue in 2016 with Authorized Rates	Change 2016 Over 2015	Change 2016 Over Current
Rg1	$1,131,077,825	$1,150,576,689	1.72%	$1,159,553,553	0.78%	2.52%
Fg1	$26,675,203	$26,136,320	-2.02%	$26,357,954	0.85%	-1.19%
Rg2	$38,082,578	$39,899,910	4.77%	$40,258,083	0.90%	5.71%
Rg3	$1,094,155	$1,245,933	13.87%	$1,257,359	0.92%	14.92%
Total Residential & Farm	$1,196,929,761	$1,217,858,852	1.75%	$1,227,426,949	0.79%	2.55%
Cg1	$243,768,559	$237,635,205	-2.52%	$239,656,986	0.85%	-1.69%
Cg6	$15,954,760	$16,736,680	4.90%	$16,887,243	0.90%	5.84%
TSS	$712,486	$682,899	-4.15%	$688,993	0.89%	-3.30%
Total Sm. General Secondary	$260,435,805	$255,054,784	-2.07%	$257,233,222	0.85%	-1.23%
Total Small Customer Class	**$1,457,365,566**	**$1,472,913,636**	**1.07%**	**$1,484,660,171**	**0.80%**	**1.87%**
Cg2 (Medium Customer Class)	**$196,963,689**	**$192,922,261**	**-2.05%**	**$194,537,930**	**0.84%**	**-1.23%**
Cg3	$578,199,153	$563,116,256	-2.61%	$568,764,304	1.00%	-1.63%
Cg3C	$5,516,392	$5,355,667	-2.91%	$5,416,713	1.14%	-1.81%
Cg3S	$1,196,409	$1,160,572	-3.00%	$1,172,673	1.04%	-1.98%
Total Large General Secondary	$584,911,954	$569,632,495	-2.61%	$575,353,690	1.00%	-1.63%
Total General Secondary	$1,042,311,448	$1,017,609,540	-2.37%	$1,027,124,842	0.94%	-1.46%
Cp1 Low	$22,728,827	$22,956,242	1.00%	$23,211,027	1.11%	2.12%
Cp1 Medium	$481,916,106	$477,632,351	-0.89%	$483,351,597	1.20%	0.30%
Cp1 High	$6,930,944	$6,940,974	0.14%	$7,023,176	1.18%	1.33%
Cp3 Medium	$34,745,049	$34,446,347	-0.86%	$34,862,498	1.21%	0.34%
Cp3S Medium	$13,082,128	$12,950,164	-1.01%	$13,107,426	1.21%	0.19%
CpFN Medium	$21,460,015	$20,329,093	-5.27%	$20,636,036	1.51%	-3.84%
CpFN High	$27,871,209	$26,739,863	-4.06%	$27,152,349	1.54%	-2.58%
CST & RTMP	$16,927,986	$16,318,286	-3.60%	$16,318,286	0.00%	-3.60%
Total General Primary	$625,662,264	$618,313,320	-1.17%	$625,662,395	1.19%	0.00%
Total Large Customer Class	**$1,210,574,218**	**$1,187,945,815**	**-1.87%**	**$1,201,016,085**	**1.10%**	**-0.79%**
Gl1	$6,655,912	$6,601,400	-0.82%	$6,621,579	0.31%	-0.52%
St1 & St2	$5,468,428	$5,452,351	-0.29%	$5,498,653	0.85%	0.55%
Cg6	$662,657	$794,154	19.84%	$802,539	1.06%	21.11%
Al1	$591,711	$591,414	-0.05%	$593,974	0.43%	0.38%
Ms1	$90,189	$89,471	-0.80%	$89,557	0.10%	-0.70%
Ms2	$2,176,182	$2,058,962	-5.39%	$2,071,481	0.61%	-4.81%
Ms3	$10,120,892	$10,108,530	-0.12%	$10,137,499	0.29%	0.16%
Ms4	$3,948,594	$3,926,197	-0.57%	$3,938,364	0.31%	-0.26%
Mg1	$4,800	$4,800	0.00%	$4,800	0.00%	0.00%
Total Street Lighting & Other	**$29,719,365**	**$29,627,279**	**-0.31%**	**$29,758,446**	**0.44%**	**0.13%**
Total Wisconsin Retail	**$2,894,622,838**	**$2,883,408,991**	**-0.39%**	**$2,909,972,632**	**0.92%**	**0.53%**
Increases (for each year)		**-$11,213,847**		**$26,563,641**		

Wisconsin Electric Power Company

Present and Authorized Electric Rates

Rate Schedules / Rate Descriptions	Present Rates	Authorized Rates in 2015	Authorized Rates in 2016	per Unit
Rg1 -- Residential Service				
Facilities Charge - Single Phase	$0.30000	$0.52602	$0.52602	per Day
Facilities Charge - Three Phase	$0.60000	$0.52602	$0.52602	per Day
Extra Meter Charge	$0.04665	$0.05951	$0.05951	per Day
Energy Charge - Base	$0.13945	$0.13111	$0.13111	per kWh
Energy Charge - Fuel Cost Adjustment	($0.00149)	($0.00058)	$0.00000	per kWh
Rg2 -- Residential Service TOU				
Facilities Charge - Single Phase	$0.30000	$0.52602	$0.52602	per Day
Facilities Charge - Three Phase	$0.60000	$0.52602	$0.52602	per Day
Extra Meter Charge	$0.04665	$0.05951	$0.05951	per Day
On-Peak Energy Charge - Base Level 1	$0.20892	$0.19680	$0.19680	per kWh
On-Peak Energy Charge - Base Level 2	$0.27585	NA	NA	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	($0.00178)	($0.00058)	$0.00000	per kWh
Off-Peak Energy Charge - Base Level 1	$0.09491	$0.08964	$0.08964	per kWh
Off-Peak Energy Charge - Base Level 2	$0.05303	NA	NA	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	($0.00132)	($0.00058)	$0.00000	per kWh
Rg3 -- Residential Service Experimental TOU				
Facilities Charge - Single Phase	$0.30000	$0.52602	$0.52602	per Day
Facilities Charge - Three Phase	$0.60000	$0.52602	$0.52602	per Day
Extra Meter Charge	$0.04665	$0.05951	$0.05951	per Day
On-Peak Energy Charge - Base Summer	$0.38602	$0.19680	$0.19680	per kWh
On-Peak Energy Charge - Base Non Summer	$0.27585	$0.19680	$0.19680	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	($0.00178)	($0.00058)	$0.00000	per kWh
Mid-Peak Energy Charge - Base Summer	$0.27585	$0.19680	$0.19680	per kWh
Mid-Peak Energy Charge - Base Non Summer	$0.20892	$0.19680	$0.19680	per kWh
Mid-Peak Energy Charge - Fuel Cost Adjustment	($0.00178)	($0.00058)	$0.00000	per kWh
Off-Peak Energy Charge - Base Annual	$0.05303	$0.08964	$0.08964	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	($0.00132)	($0.00058)	$0.00000	per kWh
Fg1 -- Farm Service				
Facilities Charge - Single Phase	$0.30000	$0.52602	$0.52602	per Day
Facilities Charge - Three Phase	$0.60000	$0.52602	$0.52602	per Day
Extra Meter Charge	$0.04665	$0.05951	$0.05951	per Day
Energy Charge - Base	$0.13945	$0.13111	$0.13111	per kWh
Energy Charge - Fuel Cost Adjustment	($0.00149)	($0.00058)	$0.00000	per kWh
Cg1 -- General Secondary Service				
Facilities Charge - Single Phase	$0.30000	$0.52602	$0.52602	per Day
Facilities Charge - Three Phase	$0.60000	$0.52602	$0.52602	per Day
Extra Meter Charge	$0.04665	$0.05951	$0.05951	per Day
Energy Charge - Base	$0.13945	$0.13282	$0.13282	per kWh
Energy Charge - Fuel Cost Adjustment	($0.00149)	($0.00058)	$0.00000	per kWh
Cg2 -- General Secondary Service - Demand				
Facilities Charge	$1.66000	$1.12590	$1.12590	per Day
Extra Meter Charge	$0.13151	$0.18542	$0.18542	per Day
On-Peak Energy Charge - Base	$0.12421	$0.12101	$0.12101	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	($0.00178)	($0.00058)	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.09169	$0.09017	$0.09017	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	($0.00132)	($0.00058)	$0.00000	per kWh
Regular On-Peak Demand Charge - Base	$6.761	$6.860	$6.860	per kW
Regular On-Peak Demand Charge - Fuel Cost Adjustment	$0.000	$0.000	$0.000	per kW
Low Hours of Use Adjustment	$0.04128	$0.04230	$0.04230	per kW per HOU less than 100
Customer Demand Charge	NA	$0.000	$0.000	per kW

Wisconsin Electric Power Company

Present and Authorized Electric Rates

Rate Schedules / Rate Descriptions	Present Rates	Authorized Rates in 2015	Authorized Rates in 2016	per Unit
Cg3 -- General Secondary Service - Demand/TOU				
Facilities Charge	$1.66000	$1.12590	$1.12590	per Day
Extra Meter Charge	$0.13151	$0.15255	$0.15255	per Day
On-Peak Energy Charge - Base	$0.08419	$0.07842	$0.07842	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	($0.00176)	($0.00058)	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.05875	$0.05622	$0.05622	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	($0.00131)	($0.00058)	$0.00000	per kWh
Regular On-Peak Demand Charge - Base	$13.385	$13.800	$13.800	per kW
Regular On-Peak Demand Charge - Fuel Cost Adjustment	$0.000	$0.000	$0.000	per kW
Low Hours of Use Adjustment	$0.08119	$0.08300	$0.08300	per kW per HOU less than 100
Customer Demand Charge	$1.800	$1.850	$1.850	per kW
Cg3C -- Gen. Sec. - Experimental Curtailable				
Facilities Charge	$3.50000	$3.50000	$3.50000	per Day
Extra Meter Charge	$0.13151	$0.15255	$0.15255	per Day
On-Peak Energy Charge - Base	$0.08419	$0.07842	$0.07842	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	($0.00176)	($0.00058)	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.05875	$0.05622	$0.05622	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	($0.00131)	($0.00058)	$0.00000	per kWh
Regular On-Peak Demand Charge - Base	$13.385	$13.800	$13.800	per kW
Regular On-Peak Demand Charge - Fuel Cost Adjustment	$0.000	$0.000	$0.000	per kW
Low Hours of Use Adjustment	$0.08119	$0.08300	$0.08300	per kW per HOU less than 100
Customer Demand Charge	$1.800	$1.850	$1.850	per kW
Curtailable Credit	$0.02080	$0.02080	$0.02080	per kW per On Peak HOU
Cg3S -- Gen. Sec. - Seasonal Curtailable				
Facilities Charge	$3.50000	$3.50000	$3.50000	per Day
Extra Meter Charge	$0.13151	$0.15255	$0.15255	per Day
On-Peak Energy Charge - Base	$0.08419	$0.07842	$0.07842	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	($0.00176)	($0.00058)	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.05875	$0.05622	$0.05622	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	($0.00131)	($0.00058)	$0.00000	per kWh
Regular On-Peak Demand Charge - Base	$13.385	$13.800	$13.800	per kW
Regular On-Peak Demand Charge - Fuel Cost Adjustment	$0.000	$0.000	$0.000	per kW
Low Hours of Use Adjustment	$0.08119	$0.08300	$0.08300	per kW per HOU less than 100
Customer Demand Charge	$1.800	$1.850	$1.850	per kW
Curtailable Credit	$2.00000	$2.00000	$2.00000	per kW per On Peak HOU
Cg6 -- General Secondary Service - TOU				
Facilities Charge - Single Phase	$0.30000	$0.52602	$0.52602	per Day
Facilities Charge - Three Phase	$0.60000	$0.52602	$0.52602	per Day
Extra Meter Charge	$0.04665	$0.05951	$0.05951	per Day
On-Peak Energy Charge - Base Level 1	$0.20892	$0.20101	$0.20101	per kWh
On-Peak Energy Charge - Base Level 2	$0.27585	NA	NA	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	($0.00178)	($0.00058)	$0.00000	per kWh
Off-Peak Energy Charge - Base Level 1	$0.09491	$0.09137	$0.09137	per kWh
Off-Peak Energy Charge - Base Level 2	$0.05303	NA	NA	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	($0.00132)	($0.00058)	$0.00000	per kWh
TSSM - General Secondary Transmission Substations - Metered				
Facilities Charge - Single Phase	$0.30000	$0.52602	$0.52602	per Day
Facilities Charge - Three Phase	$0.60000	$0.52602	$0.52602	per Day
Extra Meter Charge	$0.04665	$0.05951	$0.05951	per Day
Energy Charge - Base	$0.13945	$0.13282	$0.13282	per kWh
Energy Charge - Fuel Cost Adjustment	($0.00149)	($0.00058)	$0.00000	per kWh

Wisconsin Electric Power Company

Present and Authorized Electric Rates

Rate Schedules / Rate Descriptions	Present Rates	Authorized Rates in 2015	Authorized Rates in 2016	per Unit
TSSU - General Secondary Transmission Substations - UnMetered				
Facilities Charge	$4.00	$4.00	$4.00	per Month
Energy Charge - Base	$0.13945	$0.13282	$0.13282	per kWh
Energy Charge - Fuel Cost Adjustment	($0.00149)	($0.00058)	$0.00000	per kWh
TE1 - General Secondary Telecom Equipment - UnMetered				
Facilities Charge	$4.00	$4.00	$4.00	per Month
Energy Charge - Base	$0.13945	$0.13282	$0.13282	per kWh
Energy Charge - Fuel Cost Adjustment	($0.00149)	($0.00058)	$0.00000	per kWh
ERER1 & ERER3 Renewable Rider				
Energy for Tomorrow - 25%	$0.00600	$0.00502	$0.00502	per kWh
Energy for Tomorrow - 50%	$0.01201	$0.01004	$0.01004	per kWh
Energy for Tomorrow - 100%	$0.02401	$0.02007	$0.02007	per kWh
ERER2 Renewable Rider				
Energy for Tomorrow - < 70,000 kWh per month	$0.02401	$0.02007	$0.02007	per kWh
Energy for Tomorrow - >= 70,000 kWh per month	$0.02266	$0.01872	$0.01872	per kWh
ERER4 Renewable Rider				
Energy for Tomorrow - 25%	$0.00567	$0.00468	$0.00468	per kWh
Energy for Tomorrow - 50%	$0.01133	$0.00936	$0.00936	per kWh
Energy for Tomorrow - 100%	$0.02266	$0.01872	$0.01872	per kWh
Cp1 -- General Primary Service - TOU				
Facilities Charge	$17.26027	$19.76010	$19.76010	per Day
On-Peak Energy Charge - Base (Low Voltage)	$0.07838	$0.07530	$0.07530	per kWh
On-Peak Energy Charge - Base (Medium Voltage)	$0.07724	$0.07415	$0.07415	per kWh
On-Peak Energy Charge - Base (High Voltage)	$0.07627	$0.07324	$0.07324	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	($0.00169)	($0.00058)	$0.00000	per kWh
Off-Peak Energy Charge - Base (Low Voltage)	$0.05357	$0.05365	$0.05365	per kWh
Off-Peak Energy Charge - Base (Medium Voltage)	$0.05279	$0.05281	$0.05281	per kWh
Off-Peak Energy Charge - Base (High Voltage)	$0.05112	$0.05118	$0.05118	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	($0.00127)	($0.00058)	$0.00000	per kWh
On-Peak Demand Charge - Base (Low Voltage)	$13.052	$13.720	$13.720	per kW
On-Peak Demand Charge - Base (Meduim Voltage)	$12.861	$13.519	$13.519	per kW
On-Peak Demand Charge - Base (High Voltage)	$12.700	$13.350	$13.350	per kW
On-Peak Demand Charge - Fuel Cost Adjustment	$0.000	$0.000	$0.000	per kW
Customer Demand Charge (Low Voltage)	$1.326	$1.400	$1.400	per kW
Customer Demand Charge (Medium Voltage)	$1.306	$1.380	$1.380	per kW
Customer Demand Charge (High Voltage)	$0.000	$0.000	$0.000	per kW
Cp3 -- Gen. Pri. Service - Curtailable				
Facilities Charge	$17.26027	$19.76010	$19.76010	per Day
On-Peak Energy Charge - Base (Low Voltage)	$0.07838	$0.07530	$0.07530	per kWh
On-Peak Energy Charge - Base (Medium Voltage)	$0.07724	$0.07415	$0.07415	per kWh
On-Peak Energy Charge - Base (High Voltage)	$0.07627	$0.07324	$0.07324	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	($0.00169)	($0.00058)	$0.00000	per kWh
Off-Peak Energy Charge - Base (Low Voltage)	$0.05357	$0.05365	$0.05365	per kWh
Off-Peak Energy Charge - Base (Medium Voltage)	$0.05279	$0.05281	$0.05281	per kWh
Off-Peak Energy Charge - Base (High Voltage)	$0.05112	$0.05118	$0.05118	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	($0.00127)	($0.00058)	$0.00000	per kWh
On-Peak Demand Charge - Base (Low Voltage)	$13.052	$13.720	$13.720	per kW
On-Peak Demand Charge - Base (Medium Voltage)	$12.861	$13.519	$13.519	per kW
On-Peak Demand Charge - Base (High Voltage)	$12.700	$13.350	$13.350	per kW
On-Peak Demand Charge - Fuel Cost Adjustment	$0.000	$0.000	$0.000	per kW
Customer Demand Charge (Low Voltage)	$1.326	$1.400	$1.400	per kW
Customer Demand Charge (Medium Voltage)	$1.306	$1.380	$1.380	per kW
Customer Demand Charge (High Voltage)	$0.000	$0.000	$0.000	per kW
Curtailable Credit (Low Voltage)	$0.02028	$0.02028	$0.02028	per kW per On Peak HOU
Curtailable Credit (Medium Voltage)	$0.02000	$0.02000	$0.02000	per kW per On Peak HOU
Curtailable Credit (High Voltage)	$0.01970	$0.01970	$0.01970	per kW per On Peak HOU

Wisconsin Electric Power Company

Present and Authorized Electric Rates

Rate Schedules / Rate Descriptions	Present Rates	Authorized Rates in 2015	Authorized Rates in 2016	per Unit
Cp3S -- Gen. Pri. - Seasonal Curtailable				
Facilities Charge	$17.26027	$19.76010	$19.76010	per Day
On-Peak Energy Charge - Base (Low Voltage)	$0.07838	$0.07530	$0.07530	per kWh
On-Peak Energy Charge - Base (Medium Voltage)	$0.07724	$0.07415	$0.07415	per kWh
On-Peak Energy Charge - Base (High Voltage)	$0.07627	$0.07324	$0.07324	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	($0.00169)	($0.00058)	$0.00000	per kWh
Off-Peak Energy Charge - Base (Low Voltage)	$0.05357	$0.05365	$0.05365	per kWh
Off-Peak Energy Charge - Base (Medium Voltage)	$0.05279	$0.05281	$0.05281	per kWh
Off-Peak Energy Charge - Base (High Voltage)	$0.05112	$0.05118	$0.05118	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	($0.00127)	($0.00058)	$0.00000	per kWh
On-Peak Demand Charge - Base (Low Voltage)	$13.052	$13.720	$13.720	per kW
On-Peak Demand Charge - Base (Medium Voltage)	$12.861	$13.519	$13.519	per kW
On-Peak Demand Charge - Base (High Voltage)	$12.700	$13.350	$13.350	per kW
On-Peak Demand Charge - Fuel Cost Adjustment	$0.000	$0.000	$0.000	per kW
Customer Demand Charge (Low Voltage)	$1.326	$1.400	$1.400	per kW
Customer Demand Charge (Medium Voltage)	$1.306	$1.380	$1.380	per kW
Customer Demand Charge (High Voltage)	$0.000	$0.000	$0.000	per kW
Curtailable Credit (Low Voltage)	$2.000	$2.000	$2.000	per kW
Curtailable Credit (Medium Voltage)	$2.000	$2.000	$2.000	per kW
Curtailable Credit (High Voltage)	$2.000	$2.000	$2.000	per kW
Cp4 -- Gen. Pri. Service - Standby Service				
Facilities Charge	$17.26027	$19.76010	$19.76010	per Day
Extra Meter Charge	$6.57534	$3.14334	$3.14334	per Day
On-Peak Energy Charge - Base (Low Voltage)	$0.07838	$0.07530	$0.07530	per kWh
On-Peak Energy Charge - Base (Medium Voltage)	$0.07724	$0.07415	$0.07415	per kWh
On-Peak Energy Charge - Base (High Voltage)	$0.07627	$0.07324	$0.07324	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	($0.00169)	($0.00058)	$0.00000	per kWh
Off-Peak Energy Charge - Base (Low Voltage)	$0.05357	$0.05365	$0.05365	per kWh
Off-Peak Energy Charge - Base (Medium Voltage)	$0.05279	$0.05281	$0.05281	per kWh
Off-Peak Energy Charge - Base (High Voltage)	$0.05112	$0.05118	$0.05118	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	($0.00127)	($0.00058)	$0.00000	per kWh
On-Peak Demand Charge - Base (Low Voltage)	$13.052	$13.720	$13.720	per kW
On-Peak Demand Charge - Base (Medium Voltage)	$12.861	$13.519	$13.519	per kW
On-Peak Demand Charge - Base (High Voltage)	$12.700	$13.350	$13.350	per kW
On-Peak Demand Charge - Fuel Cost Adjustment	$0.000	$0.000	$0.000	per kW
Customer Demand Charge (Low Voltage)	$1.326	$1.400	$1.400	per kW
Customer Demand Charge (Medium Voltage)	$1.306	$1.380	$1.380	per kW
Customer Demand Charge (High Voltage)	$0.000	$0.000	$0.000	per kW
Reserved Demand Charge (Low Voltage)	$1.787	$1.993	$1.993	per kW
Reserved Demand Charge (Medium Voltage)	$1.761	$1.964	$1.964	per kW
Reserved Demand Charge (High Voltage)	$1.739	$1.939	$1.939	per kW
On-Peak Standby Energy Charge (Low Voltage)	$0.03000	$0.03000	$0.03000	per kWh
On-Peak Standby Energy Charge (Medium Voltage)	$0.03000	$0.03000	$0.03000	per kWh
On-Peak Standby Energy Charge (High Voltage)	$0.03000	$0.03000	$0.03000	per kWh
Off-Peak Standby Energy Charge (Low Voltage)	$0.02000	$0.02000	$0.02000	per kWh
Off-Peak Standby Energy Charge (Medium Voltage)	$0.02000	$0.02000	$0.02000	per kWh
Off-Peak Standby Energy Charge (High Voltage)	$0.02000	$0.02000	$0.02000	per kWh
CpFN -- Gen Pri. Combined Firm & Non Firm				
Facilities Charge	$26.30137	$26.30137	$26.30137	per Day
On-Peak Firm Energy Charge - Base (Medium Voltage)	$0.07724	$0.07415	$0.07415	per kWh
On-Peak Firm Energy Charge - Base (High Voltage)	$0.07627	$0.07324	$0.07324	per kWh
On-Peak Non Firm Energy Charge - Base (Medium Voltage)	$0.07353	$0.06922	$0.06922	per kWh
On-Peak Non Firm Energy Charge - Base (High Voltage)	$0.07261	$0.06835	$0.06835	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	($0.00169)	($0.00058)	$0.00000	per kWh
Off-Peak Firm Energy Charge - Base (Medium Voltage)	$0.05279	$0.05281	$0.05281	per kWh
Off-Peak Firm Energy Charge - Base (High Voltage)	$0.05112	$0.05118	$0.05118	per kWh
Off-Peak Non Firm Energy Charge - Base (Medium Voltage)	$0.05025	$0.04892	$0.04892	per kWh
Off-Peak Non Firm Energy Charge - Base (High Voltage)	$0.04866	$0.04737	$0.04737	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	($0.00127)	($0.00058)	$0.00000	per kWh
On-Peak Firm Demand Charge - Base (Medium Voltage)	$12.861	$13.519	$13.519	per kW
On-Peak Firm Demand Charge - Base (High Voltage)	$12.700	$13.350	$13.350	per kW
On-Peak Non Firm Demand Charge - Base (Medium Voltage)	$7.501	$8.159	$8.159	per kW
On-Peak Non Firm Demand Charge - Base (High Voltage)	$7.340	$7.990	$7.990	per kW
On-Peak Demand Charge - Fuel Cost Adjustment	$0.000	$0.000	$0.000	per kW
Customer Demand Charge (Medium Voltage)	$1.306	$1.380	$1.380	per kW
Customer Demand Charge (High Voltage)	$0.000	$0.000	$0.000	per kW

Wisconsin Electric Power Company
Present and Authorized Electric Rates

Rate Schedules / Rate Descriptions	Present Rates	Authorized Rates in 2015	Authorized Rates in 2016	per Unit
CGS1 Customer-Owned Generation - Over 20 kW				
Facilities Charge - Non Demand Metered	$0.04110	$0.05951	$0.05951	per Day
Facilities Charge - Demand Metered	$0.11507	$0.15255	$0.15255	per Day
On-Peak Purchase Price	LMP	LMP	LMP	per kWh
Off-Peak Purchase Price	LMP	LMP	LMP	per kWh
CGS3, Customer-Owned Generation - 300 kW or More				
Facilities Charge	$4.93151	$4.93151	$4.93151	per Day
Capacity Payment Secondary Voltage	$0.285	$0.395	$0.395	per kW
Capacity Payment Primary < 69 kV	$0.296	$0.411	$0.411	per kW
Capacity Payment Primary >= 69 kV	$0.300	$0.417	$0.417	per kW
Dispatched Energy Flowing Into System Secondary	$0.06486	$0.06652	$0.06652	per kWh
Dispatched Energy Flowing Into System Pri Medium Voltage	$0.06750	$0.06923	$0.06923	per kWh
Dispatched Energy Flowing Into System Pri High Voltage	$0.06836	$0.07010	$0.07010	per kWh
Dispatched Displaced Energy Secondary	$0.00000	$0.00000	$0.00000	per kWh
Dispatched Displaced Energy Primary Medium Voltage	$0.00000	$0.00000	$0.00000	per kWh
Dispatched Displaced Energy Primary High Voltage	$0.00000	$0.00000	$0.00000	per kWh
Purchased Non-Dispatched Energy Secondary	$0.02478	$0.02612	$0.02612	per kWh
Purchased Non-Dispatched Energy Primary Medium Voltage	$0.02579	$0.02719	$0.02719	per kWh
Purchased Non-Dispatched Energy Primary High Voltage	$0.02611	$0.02753	$0.02753	per kWh
CGS5 Customer-Owned Generation - Biogas - 2000 kW or Less				
On-Peak Purchase Price	$0.15500	$0.15500	$0.15500	per kWh
Off-Peak Purchase Price	$0.06140	$0.06140	$0.06140	per kWh
CGS8 Customer-Owned Generation - Renewable - 20 kW or Less				
Flat Purchase Price	$0.03712	$0.04245	$0.04245	per kWh
On-Peak Purchase Price	$0.04545	$0.04982	$0.04982	per kWh
Off-Peak Purchase Price	$0.03265	$0.03849	$0.03849	per kWh
COGS-NM Customer-Owned Generation Net Metering 300 kW or Less				
Facilites Charge (Rg1, Rg2, Cg1, Cg6)	NA	NA	$0.05951	per Day
Facilites Charge (Cg2, Cg3, Cg3C, Cg3S)	NA	NA	$0.15255	per Day
Facilites Charge (Cp1, Cp3, CpFN)	NA	NA	$3.14334	per Day
Capacity Demand Charge for Non-Intermittent Generation (Rg1, Rg2, Cg1, Cg2)	NA	NA	$8.602	per kW
Capacity Demand Charge for Intermittent Generation (Rg1, Rg2, Cg1, Cg2)	NA	NA	$3.794	per kW
Capacity Demand Charge (Cg3, Cg3C, Cg3S)	NA	NA	$5.177	per kW
Capacity Demand Charge (Cp1, Cp3, CpFN Low & Medium Voltage)	NA	NA	$4.793	per kW
Capacity Demand Charge (Cp1, Cp3, CpFN High Voltage)	NA	NA	$4.732	per kW
Flat-Rate Purchase Price (Secondary)	NA	NA	$0.04245	per kWh
Summer On-Peak Purchase Price (Secondary)	NA	NA	$0.05714	per kWh
Summer Off-Peak Purchase Price (Secondary)	NA	NA	$0.03876	per kWh
Non-Summer On-Peak Purchase Price (Secondary)	NA	NA	$0.04608	per kWh
Non-Summer Off-Peak Purchase Price (Secondary)	NA	NA	$0.03836	per kWh
Summer On-Peak Purchase Price (Low Voltage Primary)	NA	NA	$0.05572	per kWh
Summer Off-Peak Purchase Price (Low Voltage Primary)	NA	NA	$0.03780	per kWh
Non-Summer On-Peak Purchase Price (Low Voltage Primary)	NA	NA	$0.04493	per kWh
Non-Summer Off-Peak Purchase Price (Low Voltage Primary)	NA	NA	$0.03741	per kWh
Summer On-Peak Purchase Price (Medium Voltage Primary)	NA	NA	$0.05491	per kWh
Summer Off-Peak Purchase Price (Medium Voltage Primary)	NA	NA	$0.03725	per kWh
Non-Summer On-Peak Purchase Price (Medium Voltage Primary)	NA	NA	$0.04427	per kWh
Non-Summer Off-Peak Purchase Price (Medium Voltage Primary)	NA	NA	$0.03686	per kWh
Summer On-Peak Purchase Price (High Voltage Primary)	NA	NA	$0.05422	per kWh
Summer Off-Peak Purchase Price (High Voltage Primary)	NA	NA	$0.03678	per kWh
Non-Summer On-Peak Purchase Price (High Voltage Primary)	NA	NA	$0.04372	per kWh
Non-Summer Off-Peak Purchase Price (High Voltage Primary)	NA	NA	$0.03640	per kWh

Wisconsin Electric Power Company

Present and Authorized Electric Rates

Rate Schedules / Rate Descriptions	Present Rates	Authorized Rates in 2015	Authorized Rates in 2016	per Unit
COGS-DS-FP Customer-Owned Generation Direct Sale Fixed Price				
Facilites Charge (Rg1, Rg2, Cg1, Cg6)	NA	NA	$0.05951	per Day
Facilites Charge (Cg2, Cg3, Cg3C, Cg3S)	NA	NA	$0.15255	per Day
Facilites Charge (Cp1, Cp3, CpFN)	NA	NA	$3.14334	per Day
Flat-Rate Purchase Price (Secondary)	NA	NA	$0.04245	per kWh
Summer On-Peak Purchase Price (Secondary)	NA	NA	$0.05714	per kWh
Summer Off-Peak Purchase Price (Secondary)	NA	NA	$0.03876	per kWh
Non-Summer On-Peak Purchase Price (Secondary)	NA	NA	$0.04608	per kWh
Non-Summer Off-Peak Purchase Price (Secondary)	NA	NA	$0.03836	per kWh
Summer On-Peak Purchase Price (Low Voltage Primary)	NA	NA	$0.05572	per kWh
Summer Off-Peak Purchase Price (Low Voltage Primary)	NA	NA	$0.03780	per kWh
Non-Summer On-Peak Purchase Price (Low Voltage Primary)	NA	NA	$0.04493	per kWh
Non-Summer Off-Peak Purchase Price (Low Voltage Primary)	NA	NA	$0.03741	per kWh
Summer On-Peak Purchase Price (Medium Voltage Primary)	NA	NA	$0.05491	per kWh
Summer Off-Peak Purchase Price (Medium Voltage Primary)	NA	NA	$0.03725	per kWh
Non-Summer On-Peak Purchase Price (Medium Voltage Primary)	NA	NA	$0.04427	per kWh
Non-Summer Off-Peak Purchase Price (Medium Voltage Primary)	NA	NA	$0.03686	per kWh
Summer On-Peak Purchase Price (High Voltage Primary)	NA	NA	$0.05422	per kWh
Summer Off-Peak Purchase Price (High Voltage Primary)	NA	NA	$0.03678	per kWh
Non-Summer On-Peak Purchase Price (High Voltage Primary)	NA	NA	$0.04372	per kWh
Non-Summer Off-Peak Purchase Price (High Voltage Primary)	NA	NA	$0.03640	per kWh
COGS-DS-VP Customer-Owned Generation Direct Sale Variable Price				
Facilites Charge (Rg1, Rg2, Cg1, Cg6)	NA	NA	$0.05951	per Day
Facilites Charge (Cg2, Cg3, Cg3C, Cg3S)	NA	NA	$0.15255	per Day
Facilites Charge (Cp1, Cp3, CpFN)	NA	NA	$3.14334	per Day
On-Peak Purchase Price	NA	NA	LMP	per kWh
Off-Peak Purchase Price	NA	NA	LMP	per kWh
COGS-NP Customer-Owned Generation Non Purchase				
Capacity Demand Charge for Non-Intermittent Generation (Rg1, Rg2, Cg1, Cg2)	NA	NA	$8.602	per kW
Capacity Demand Charge for Intermittent Generation (Rg1, Rg2, Cg1, Cg2)	NA	NA	$3.794	per kW
Capacity Demand Charge (Cg3, Cg3C, Cg3S)	NA	NA	$5.177	per kW
Capacity Demand Charge (Cp1, Cp3, CpFN Low & Medium Voltage)	NA	NA	$4.793	per kW
Capacity Demand Charge (Cp1, Cp3, CpFN High Voltage)	NA	NA	$4.732	per kW
St1 -- Optional TOU Street Lighting Service				
Facilities Charge - Single Phase	$0.30000	$0.52602	$0.52602	per Day
Facilities Charge - Three Phase	$0.60000	$0.52602	$0.52602	per Day
Extra Meter Charge	$0.04665	$0.05951	$0.05951	per Day
On-Peak Energy Charge	$0.27552	$0.27552	$0.27552	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	($0.00178)	($0.00058)	$0.00000	per kWh
Off-Peak Energy Charge	$0.05195	$0.05195	$0.05195	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	($0.00132)	($0.00058)	$0.00000	per kWh
St2 -- Optional TOU Street Lighting Service				
Facilities Charge - Single Phase	NA	$0.52602	$0.52602	per Day
Facilities Charge - Three Phase	NA	$0.52602	$0.52602	per Day
Extra Meter Charge	NA	$0.05951	$0.05951	per Day
On-Peak Energy Charge	NA	$0.28449	$0.28449	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	NA	($0.00058)	$0.00000	per kWh
Off-Peak Energy Charge	NA	$0.05471	$0.05471	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	NA	($0.00058)	$0.00000	per kWh

Wisconsin Electric Power Company

Present and Authorized Electric Rates

Rate Schedules / Rate Descriptions	Present Rates	Authorized Rates in 2015	Authorized Rates in 2016	per Unit
Gl1 - Area Lighting				
Standard High Pressure Sodium				
50 Watt	$10.08	$10.04	$10.04	per Month
70 Watt	$11.67	$11.63	$11.63	per Month
100 Watt	$13.57	$13.52	$13.52	per Month
150 Watt	$15.81	$15.75	$15.75	per Month
200 Watt	$18.42	$18.35	$18.35	per Month
250 Watt	$20.90	$20.83	$20.83	per Month
400 Watt	$27.80	$27.69	$27.69	per Month
Flood High Presure Sodium				
70 Watt	$13.21	$13.16	$13.16	per Month
100 Watt	$15.07	$15.01	$15.01	per Month
150 Watt	$17.34	$17.27	$17.27	per Month
200 Watt	$19.83	$19.76	$19.76	per Month
250 Watt	$22.26	$22.17	$22.17	per Month
400 Watt	$28.98	$28.87	$28.87	per Month
Standard Metal Halide				
175 Watt	$25.24	$25.14	$25.14	per Month
250 Watt	$26.51	$26.41	$26.41	per Month
400 Watt	$30.69	$30.57	$30.57	per Month
Flood Metal Halide				
175 Watt	$26.55	$26.45	$26.45	per Month
250 Watt	$27.96	$27.85	$27.85	per Month
400 Watt	$31.94	$31.82	$31.82	per Month
1000 Watt	$60.86	$60.63	$60.63	per Month
Poles	$2.81	$2.80	$2.80	per Month
Spans	$2.74	$2.73	$2.73	per Month
Energy Charge - Fuel Cost Adjustment	($0.00137)	($0.00058)	$0.00000	per kWh
Al1 - Alley Lighting				
0 - 10 Watt LED	$2.33	$2.32	$2.32	per Month
>10 - 20 Watt LED	$2.66	$2.65	$2.65	per Month
>20 - 30 Watt LED	$3.07	$3.06	$3.06	per Month
>30 - 40 Watt LED	$3.49	$3.48	$3.48	per Month
>40 - 50 Watt LED	$3.90	$3.89	$3.89	per Month
>50 - 60 Watt LED	$4.31	$4.29	$4.29	per Month
50 Watt HPS	$4.31	$4.29	$4.29	per Month
70 Watt HPS	$5.40	$5.38	$5.38	per Month
100 Watt HPS	$7.27	$7.24	$7.24	per Month
Energy Charge - Fuel Cost Adjustment	($0.00137)	($0.00058)	$0.00000	per kWh
Ms1 - Highway Lighting				
Facilities - 25 Watts or Less	$3.06	$3.06	$3.06	per Month
Facilities - 25 Watts to 75 Watts	$3.13	$3.13	$3.13	per Month
Facilities - Greater than 75 Watts	$5.02	$5.02	$5.02	per Month
Energy Charge - Base	$0.13945	$0.13282	$0.13282	per kWh
Energy Charge - Fuel Cost Adjustment	($0.00137)	($0.00058)	$0.00000	per kWh
Ms2 - Street Lighting				
Energy Charge - Base	$0.12551	$0.11954	$0.11954	per kWh
Energy Charge - Fuel Cost Adjustment	($0.00137)	($0.00058)	$0.00000	per kWh

Wisconsin Electric Power Company

Present and Authorized Electric Rates

Rate Schedules / Rate Descriptions	Present Rates	Authorized Rates in 2015	Authorized Rates in 2016	per Unit
Ms3 - Street Lighting				
High Pressure Sodium Lamps				
50 Watt	$10.08	$10.04	$10.04	per Month
70 Watt	$11.67	$11.63	$11.63	per Month
100 Watt	$13.57	$13.52	$13.52	per Month
150 Watt	$15.81	$15.75	$15.75	per Month
200 Watt	$18.42	$18.35	$18.35	per Month
250 Watt	$20.90	$20.83	$20.83	per Month
400 Watt	$27.80	$27.69	$27.69	per Month
Metal Halide Lamps				
175 Watt	$25.24	$25.14	$25.14	per Month
250 Watt	$26.51	$26.41	$26.41	per Month
400 Watt	$30.69	$30.57	$30.57	per Month
Energy Charge - Fuel Cost Adjustment	($0.00137)	($0.00058)	$0.00000	per kWh
Ms4 - Street Lighting				
Facilities Charge - Option A	1.90%	1.90%	1.90%	per Month
Facilities Charge - Option B	0.50%	0.50%	0.50%	per Month
Non-Standard Lamps				
50 Watt HPS	$2.31	$2.30	$2.30	per Month
70 Watt HPS	$3.40	$3.39	$3.39	per Month
100 Watt HPS	$5.27	$5.25	$5.25	per Month
150 Watt HPS	$7.47	$7.44	$7.44	per Month
175 Watt MH	$8.46	$8.43	$8.43	per Month
200 Watt HPS	$9.88	$9.84	$9.84	per Month
250 Watt HPS	$12.30	$12.25	$12.25	per Month
400 Watt HPS	$19.00	$18.93	$18.93	per Month
1000 Watt HPS	$44.26	$44.09	$44.09	per Month
Energy Charge - Fuel Cost Adjustment	($0.00137)	($0.00058)	$0.00000	per kWh
Mg1 - Municipal Defense Sirens				
Facilities Charge	$3.00	$3.00	$3.00	per Month
Energy Charge - Base	$0.13945	$0.13282	$0.13282	per kWh
Energy Charge - Fuel Cost Adjustment	($0.00137)	($0.00058)	$0.00000	per kWh
Embedded Credits for Line Extensions				
Rg1, Rg2, Rg3 & Fg1 Single Phase	$1,043	$1,114	$1,114	per Customer
Rg1, Rg2, Rg3 & Fg1 Three Phase	$3,128	$3,342	$3,342	per Customer
Cg1 & Cg6 Single Phase	$1,215	$1,235	$1,235	per Customer
Cg1 & Cg6 Three Phase	$2,429	$2,471	$2,471	per Customer
Cg2, Cg3 & Cg3C	$90.50	$111.39	$111.39	per kW
TE1	$4.05	$4.39	$4.39	per Customer
General Primary	$90.32	$110.99	$110.99	per kW
Standard Street Lighting	$81.55	$86.50	$86.50	per Lamp
Act 141 Costs Embedded in Base Rates				
Rg1, Rg2, Rg3, Fg1	$0.00184	$0.00195	$0.00195	per kWh
Cg1, Cg2, Cg3, Cg3C, Cg6, TSSM, TSSU,	$0.00152	$0.00320	$0.00320	per kWh
Cp1, Cp3, Cp4, CpFN	$0.00152	$0.00320	$0.00320	per kWh
Gl1, St1, St2, Al1, Ms1, Ms2, Ms3, Ms4, Mg1, TE1	$0.00152	$0.00320	$0.00320	per kWh
Biomass Tax Grant Credit				
Rg1, Rg2, Rg3, Fg1, Cg1, Cg6, TSSM, TSSU	($0.00081)	($0.00063)	$0.00000	per kWh
Cg2	($0.00074)	($0.00048)	$0.00000	per kWh
Cg3, Cg3C, Cg3S, Cp1, Cp3, Cp3S, Cp4, CpFN	($0.00066)	($0.00048)	$0.00000	per kWh
Gl1, St1, St2, Al1, Ms1, Ms2, Ms3, Ms4, Mg1 (metered only), TE1	($0.00030)	($0.00013)	$0.00000	per kWh

Wisconsin Electric Power Company
Steam Revenue Summary
for Test Year ending December 31, 2015 & for 2016

	Revenue in TY2015 with Present Rates	Revenue in 2015 with Authorized Rates	Change 2015 Over Present	Revenue in 2016 with Authorized Rates	Change 2016 Over 2015
Downtown Milwaukee Steam [1]					
Ag-1 Downtown Milwaukee	$23,452,986	$23,942,300	2.09%	$23,942,300	0.00%
Ag-4 Downtown Milwaukee	$375,252	$367,083	-2.18%	$367,083	0.00%
Downtown Milwaukee Total	$23,828,238	$24,309,383	2.02%	$24,309,383	0.00%
Downtown Milwaukee Increases		**$481,145**	**2.02%**	**$0**	**0.00%**
Wauwatosa Steam [2]					
Ag-1 Wauwatosa	$17,123,175	$18,364,557	7.25%	$18,364,557	0.00%
Wauwatosa Steam Increases		**$1,241,382**	**7.25%**	**$0**	**0.00%**
Total Steam	$40,951,413	$42,673,940	4.21%	$42,673,940	0.00%
Total Steam Increases		**$1,722,527**	**4.21%**	**$0**	**0.00%**

Note [1] -- Downtown Milwaukee Steam is also referred to as the Valley Steam operations
Note [2] -- Wauwatosa Steam is also referred to as the Milwaukee County Steam operations

Wisconsin Electric Power Company
Present and Authorized Steam Rates

Rate Schedule / Rate Description	Present Rates	Authorized Rates for 2015	Authorized Rates for 2016	per Unit
Ag1 Downtown Milwaukee Steam				
Facilities Charge per Customer Day	$0.66	$2.50	$2.50	per Day
Production Energy Charge	$5.56596	-	-	per MLbs
Distribution Energy Charge	$6.67528	-	-	per MLbs
Ratcheted Demand Charge	-	$0.71445	$0.71445	per MLbs
Combined Energy Charge	-	$11.19748	$11.19748	per MLbs
Fuel Cost included in Base Production Rate	$3.77252	$4.03681	$4.03681	$/million BTU
Conversion Rate from million BTU production to MLBS sales	1.032	0.976	0.976	
Ag2 Downtown Milwaukee Steam				
Facilities Charge per Customer Day	$0.50	$2.50	$2.50	per Day
Production Energy Charge	$5.56596	-	-	per MLbs
Distribution Energy Charge	$0.00000	-	-	per MLbs
Ratcheted Demand Charge	-	$0.25489	$0.25489	per MLbs
Combined Energy Charge	-	$3.99485	$3.99485	per MLbs
Quantity Credit for Returned Condensate	($0.13221)	($0.13221)	($0.13221)	per MLbs
Quality Credit for Returned Condensate	($0.30409)	($0.30409)	($0.30409)	per MLbs
Fuel Cost included in Base Production Rate	$3.77252	$4.03681	$4.03681	$/million BTU
Conversion Rate from million BTU production to MLBS sales	1.032	0.976	0.976	
Ag4 Downtown Milwaukee Steam				
Facilities Charge per Customer Day	$3.50	$2.50	$2.50	per Day
Production Energy Charge	$4.29850	-	-	per MLbs
Distribution Energy Charge	$6.67525	-	-	per MLbs
Ratcheted Demand Charge	-	$0.71445	$0.71445	per MLbs
Combined Energy Charge	-	$9.97082	$9.97082	per MLbs
Fuel Cost included in Base Production Rate	$3.77252	$4.03681	$4.03681	$/million BTU
Conversion Rate from million BTU production to MLBS sales	1.032	0.976	0.976	
Ag1 Wauwatosa Steam				
Facilities Charge per Customer Day	$0.50	$2.50	$2.50	per Day
Production Energy Charge	$19.68429	$24.23169	$24.23169	per MLbs
Distribution Energy Charge	$4.98595	$3.72975	$3.72975	per MLbs
Fuel Cost included in Base Production Rate	$3.84045	$5.12709	$5.12709	$/million BTU
Conversion Rate from million BTU production to MLBS sales	1.585	1.474	1.474	
Embedded Credits				
Downtown Milwaukee	$13.00	$ 14.00	$ 14.00	per MLbs
Wauwatosa	$10.00	$ 15.00	$ 15.00	per MLbs

Bundled 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 and Rely-A-Bill								
WEGO Residential (Rg-1)	333,192,964	$ 109,407,266	$ 180,295,877	$ 289,703,142	$ (6,967,816)	$ 282,735,327	(2.41)%	(6.37)%
WEGO Rely-A-Bill (Rf-1)	-	$ 678,900	$ -	$ 678,900	$ 43,800	$ 722,700	6.45%	6.45%
Subtotal	333,192,964	$ 110,086,166	$ 180,295,877	$ 290,382,042	$ (6,924,016)	$ 283,458,027	(2.38)%	(6.29)%
Commercial & Industrial, g-1 (0 to 3,999)								
WEGO Firm Comm. Ind. (Fg-1)	35,829,933	$ 9,853,127	$ 19,535,439	$ 29,388,567	$ (872,639)	$ 28,515,928	(2.97)%	(8.86)%
WEGO Agricultural Seasonal Use (Ag-1)	217,460	$ 47,685	$ 102,656	$ 150,342	$ (6,078)	$ 144,264	(4.04)%	(12.75)%
WEGO Natural Gas Vehicles 1 (NGV-1)	16,703	$ 3,707	$ 8,001	$ 11,708	$ (464)	$ 11,244	(3.96)%	(12.52)%
Subtotal	36,064,096	$ 9,904,520	$ 19,646,096	$ 29,550,616	(879,181)	28,671,435	(2.98)%	(8.88)%
Commercial & Industrial, g-2 (4,000 to 39,999)								
WEGO Firm Comm. Ind. (Fg-2)	99,883,588	$ 17,456,609	$ 53,968,984	$ 71,425,593	$ (1,638,091)	$ 69,787,503	(2.29)%	(9.38)%
WEGO Agricultural Seasonal Use (Ag-2)	1,474,986	$ 247,060	$ 694,899	$ 941,959	$ (24,190)	$ 917,769	(2.57)%	(9.79)%
WEGO Natural Gas Vehicles 2 (NGV-2)	786,104	$ 125,353	$ 378,334	$ 503,687	$ (12,892)	$ 490,795	(2.56)%	(10.28)%
WEGO Transport Commercial 2 (Tf-2)	2,712,640	$ 415,391	$ (9,317)	$ 406,074	$ (44,487)	$ 361,587	(10.96)%	(10.71)%
Subtotal	104,857,318	$ 18,244,413	$ 55,032,900	$ 73,277,314	(1,719,660)	71,557,654	(2.35)%	(9.43)%
Commercial & Industrial, g-3 (40,000 to 99,999)								
WEGO Firm Comm. Ind. (Fg-3)	29,172,520	$ 3,955,147	$ 15,645,152	$ 19,600,299	$ (233,380)	$ 19,366,918	(1.19)%	(5.90)%
WEGO Agricultural Seasonal Use (Ag-3)	496,260	$ 78,884	$ 234,119	$ 313,003	$ (3,970)	$ 309,033	(1.27)%	(5.03)%
WEGO Natural Gas Vehicles 3 (NGV-3)	910,537	$ 124,987	$ 437,035	$ 562,022	$ (7,284)	$ 554,738	(1.30)%	(5.83)%
WEGO Inter. Comm. Ind. (Ig-3)	-	$ -	$ -	$ -	$ -	$ -	- %	- %
WEGO Transport Commercial 3 (Tf-3)	9,253,474	$ 1,050,127	$ (31,783)	$ 1,018,345	$ (74,028)	$ 944,317	(7.27)%	(7.05)%
Subtotal	39,832,791	$ 5,209,145	$ 16,284,523	$ 21,493,668	(318,662)	21,175,006	(1.48)%	(6.12)%
Commercial & Industrial g-4 (100,000 to 499,999)								
WEGO Firm Comm. Ind. (Fg-4)	19,854,883	$ 2,305,979	$ 10,530,855	$ 12,836,835	$ (99,274)	$ 12,737,560	(0.77)%	(4.31)%
WEGO Agricultural Seasonal Use (Ag-4)	274,304	$ 33,842	$ 128,496	$ 162,338	$ (1,372)	$ 160,966	(0.84)%	(4.05)%
WEGO Inter. Comm. Ind. (Ig-4)	3,648,810	$ 399,566	$ 1,702,753	$ 2,102,319	$ (18,244)	$ 2,084,075	(0.87)%	(4.57)%
WEGO Transport Commercial 4 (Tf-4)	45,488,800	$ 3,678,758	$ (156,239)	$ 3,522,519	$ (227,444)	$ 3,295,075	(6.46)%	(6.18)%
Subtotal	69,266,797	$ 6,418,145	$ 12,205,865	$ 18,624,010	(346,334)	18,277,676	(1.86)%	(5.40)%
Commercial & Industrial g-5 (500,000 to 999,999)								
WEGO Firm Comm. Ind. (Fg-5)	1,320,825	$ 134,782	$ 681,984	$ 816,767	$ (6,604)	$ 810,162	(0.81)%	(4.90)%
WEGO Agricultural Seasonal Use (Ag-5)	-	$ -	$ -	$ -	$ -	$ -	- %	- %
WEGO Inter. Comm. Ind. (Ig-5)	736,183	$ 72,038	$ 343,547	$ 415,585	$ (3,681)	$ 411,904	(0.89)%	(5.11)%
WEGO Transport Commercial 5 (Tf-5)	33,183,013	$ 2,572,391	$ (113,973)	$ 2,458,418	$ (165,915)	$ 2,292,503	(6.75)%	(6.45)%
Subtotal	35,240,021	$ 2,779,211	$ 911,559	$ 3,690,770	(176,200)	3,514,570	(4.77)%	(6.34)%
Commercial & Industrial g-6 (1,000,000 to 7,999,999)								
WEGO Firm Comm. Ind. (Fg-6)	-	$ -	$ -	$ -	$ -	$ -	- %	- %
WEGO Inter. Comm. Ind. (Ig-6)	-	$ -	$ -	$ -	$ -	$ -	- %	- %
WEGO Transport Commercial 6 (Tf-6)	84,283,182	$ 4,620,697	$ (289,485)	$ 4,331,212	$ (210,708)	$ 4,120,505	(4.86)%	(4.56)%
Subtotal	84,283,182	$ 4,620,697	$ (289,485)	$ 4,331,212	(210,708)	4,120,505	(4.86)%	(4.56)%
Commercial & Industrial, g-7 (8,000,000 and over)								
WEGO Firm Comm. Ind. (Fg-7)	-	$ -	$ -	$ -	$ -	$ -	- %	- %
WEGO Inter. Comm. Ind. (Ig-7)	-	$ -	$ -	$ -	$ -	$ -	- %	- %
WEGO Transport Commercial 7 (Tf-7)	69,235,607	$ 2,313,132	$ (237,801)	$ 2,075,331	$ (76,159)	$ 1,999,171	(3.67)%	(3.29)%
Subtotal	69,235,607	$ 2,313,132	$ (237,801)	$ 2,075,331	(76,159)	1,999,171	(3.67)%	(3.29)%
Power Generators	11,401,570	$ 2,724,669	$ (39,161)	$ 2,685,508	$ (10,001)	$ 2,675,507	(0.37)%	(0.37)%
Special Contracts	51,780,090	$ 171,761	$ -	$ 171,761	$ -	$ 171,761	- %	- %
Subtotal	63,181,660	$ 2,896,430	$ (39,161)	$ 2,857,269	(10,001)	2,847,268	(0.35)%	(0.35)%
Total Gas Sales Revenues	835,154,436	$ 162,471,860	$ 283,810,373	$ 446,282,233	$ (10,660,921)	$ 435,621,312	(2.39)%	(6.56)%
Plus:								
Other Gas Revenue				$ 1,312,000		$ 1,312,000		
Total Gas Operating Revenue				$ 447,594,233		$ 436,933,312	(2.38)%	

Gas Rate Comparison
Present and Authorized Gas Rates

	Present Margin	Authorized Margin
Residential		
Daily Basic Distribution Charge (Rg-1, Rt-1)	$ 0.31	$ 0.33
Transportation Administrative Charge (Rt-1)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Rg-1, Rt-1)	$ 0.1441	$ 0.1137
Daily Balancing Charge (Rg-1, Rt-1)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Rg-1)	$ 0.0332	$ 0.0332
Peak Day Backup Charge (Rg-1)	$ 0.0022	$ 0.0022
Commercial (0 to 3,999)		
Daily Basic Distribution Charge (Fg-1, Ag-1, NGV-1, Tf-1)	$ 0.31	$ 0.33
Transportation Administrative Charge (Tf-1)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Fg-1, Ag-1, NGV-1, Tf-1)	$ 0.1441	$ 0.1137
Daily Balancing Charge (Fg-1, Ag-1, NGV-1, Tf-1)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Fg-1, NGV-1, Ag-1)	$ 0.0332	$ 0.0332
Peak Day Backup Charge (Fg-1, NGV-1, Ag-1)	$ 0.0022	$ 0.0022
Commercial (4,000 to 39,999)		
Daily Basic Distribution Charge (Fg-2, Ag-2, NGV-2, Tf-2)	$ 0.85	$ 0.85
Transportation Administrative Charge (Tf-2)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Fg-2, Ag-2, NGV-2, Tf-2)	$ 0.1126	$ 0.0962
Daily Balancing Charge (Fg-2, Ag-2, NGV-2, Tf-2)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Fg-2, Ag-2, NGV-2)	$ 0.0326	$ 0.0326
Peak Day Backup Charge (Fg-2, Ag-2, NGV-2)	$ 0.0022	$ 0.0022
Commercial (40,000 to 99,999)		
Daily Basic Distribution Charge (Fg-3, Ag-3, NGV-3, Tf-3)	$ 6.00	$ 6.00
Transportation Administrative Charge (Tf-3)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Fg-3, Ag-3, NGV-3, Tf-3)	$ 0.0694	$ 0.0614
Daily Balancing Charge (Fg-3, Ag-3, NGV-3, Tf-3)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Fg-3, Ag-3, NGV-3)	$ 0.0326	$ 0.0326
Peak Day Backup Charge (Fg-3, Ag-3, NGV-3)	$ 0.0022	$ 0.0022

Gas Rate Comparison
Present and Authorized Gas Rates

	Present Margin	Authorized Margin
Commercial (100,000 to 499,999)		
Daily Basic Distribution Charge (Fg-4, Ag-4, Ig-4, Tf-4)	$ 11.00	$ 11.00
Transportation Administrative Charge (Tf-4)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Fg-4, Ag-4, Ig-4, Tf-4)	$ 0.0604	$ 0.0554
Daily Balancing Charge (Fg-4, Ag-4, Ig-4, Tf-4)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Fg-4, Ag-4, Ig-4)	$ 0.0297	$ 0.0297
Peak Day Backup Charge (Fg-4, Ag-4)	$ 0.0022	$ 0.0022
Commercial (500,000 to 999,999)		
Daily Basic Distribution Charge (Fg-5, Ag-5, Ig-5, Tf-5)	$ 35.00	$ 35.00
Transportation Administrative Charge (Tf-5)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Fg-5, Ag-5, Ig-5, Tf-5)	$ 0.0570	$ 0.0520
Daily Balancing Charge (Fg-5, Ag-5, Ig-5, Tf-5)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Fg-5, Ag-5, Ig-5)	$ 0.0217	$ 0.0217
Peak Day Backup Charge (Fg-5, Ag-5)	$ 0.0022	$ 0.0022
Commercial (1,000,000 to 7,999,999)		
Daily Basic Distribution Charge (Fg-6, Ig-6, Tf-6)	$ 115.00	$ 115.00
Transportation Administrative Charge (Tf-6)	$ 2.00	$ 2.00
Volumetric Charges:		
Demand Charge (Fg-6, Ig-6, Tf-6)	$ 0.0030	$ 0.0030
Distribution Service Charge (Fg-6, Ig-6, Tf-6)	$ 0.0268	$ 0.0243
Daily Balancing Charge (Fg-6, Ig-6, Tf-6)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Fg-6, Ig-6)	$ 0.0134	$ 0.0134
Peak Day Backup Charge (Fg-6)	$ 0.0022	$ 0.0022
Commercial (8,000,000 +)		
Daily Basic Distribution Charge (Fg-7, Ig-7, Tf-7)	$ 450.00	$ 450.00
Transportation Administrative Charge (Tf-7)	$ 2.00	$ 2.00
Volumetric Charges:		
Demand Charge (Fg-7, Ig-7, Tf-7)	$ 0.0024	$ 0.0024
Distribution Service Charge (Fg-7, Ig-7, Tf-7)	$ 0.0163	$ 0.0152
Daily Balancing Charge (Fg-7, Ig-7, Tf-7)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Fg-7, Ig-7)	$ 0.0119	$ 0.0119
Peak Day Backup Charge (Fg-7)	$ 0.0022	$ 0.0022

Gas Rate Comparison
Present and Authorized Gas Rates

		Present Margin	Authorized Margin
Base Gas Cost Rates:			
Average Peak Day Demand Costs - Volumetric		$ 0.0929	$ 0.0896
Average Annual Demand Costs		$ 0.0241	$ 0.0272
Average Commodity Costs		$ 0.3665	$ 0.4429
Gas Lost and Unaccounted For		$ (0.0017)	$ (0.0034)
Daily Cashout Charges:			
Competitive Supply		$ 0.0177	$ 0.0181
Peak Day Backup		$ 0.0022	$ 0.0022
Act 141 Volumetric Distribution Rates 1/			
Residential		0.0124	$ 0.0076
Commercial G-1	(0 to 3,999)	0.0224	$ 0.0133
Commercial G-2	(4,000 to 39,999)	0.0224	$ 0.0133
Commercial G-3	(40,000 to 99,999)	0.0224	$ 0.0133
Commercial G-4	(100,000 to 499,999)	0.0224	$ 0.0133
Commercial G-5	(500,000 to 999,999)	0.0224	$ 0.0133
Commercial G-6	(1,000,000 to 7,999,999)	0.0001	$ 0.0001
Commercial G-7	(8,000,000 +)	0.0001	$ 0.0001

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

	Present Margin	Authorized Margin
Electric Generation Special Contract Service		
Fixed Daily Charges		
Pt-2	$ 600.00	$ 600.00
Pt-6	$ 1,444.00	$ 1,444.00
Pt-7	$ 267.00	$ 267.00
Pt-8	$ 331.00	$ 331.00
Pt-9	$ 253.20	$ 253.20
Volumetric Charges		
Pt-2	$ 0.0087	$ 0.0076
Pt-6	$ 0.0265	$ 0.0254
Pt-7	$ 0.0258	$ 0.0247
Pt-8	$ 0.0256	$ 0.0245
Pt-9	$ 0.0015	$ 0.0015
Demand Charge:		
Pt-9	$ 0.0150	$ 0.0150

WE-GO Residential Monthly Bill Impact Analysis

Gas Costs	Summer	Winter
Firm Service	0.4667	0.5562

Monthly Use Therms	Present Customer Charge	Current Admin. & Distribut'n Charges	Total Monthly Cost	Gas Costs	Total Costs	Authorized Admin. & Customer Charges	Authorized Admin. & Distribut'n Charges	Authorized Total Monthly Cost	Gas Costs	Total Costs	Monthly Bill Increase (Decrease)	Monthly Percent Increase (Decrease)
Rg-1: Residential Firm Sales Service During Summer Months												
5	$ 9.43	$ 0.91	$ 10.34	$ 2.33	$ 12.67	$ 10.04	$ 0.75	$ 10.79	$ 2.33	$ 13.13	$ 0.46	3.60%
15	$ 9.43	$ 2.72	$ 12.15	$ 7.00	$ 19.15	$ 10.04	$ 2.26	$ 12.30	$ 7.00	$ 19.30	$ 0.15	0.80%
21 avg.	$ 9.43	$ 3.81	$ 13.24	$ 9.80	$ 23.04	$ 10.04	$ 3.17	$ 13.21	$ 9.80	$ 23.01	$ (0.03)	(0.13)%
35	$ 9.43	$ 6.35	$ 15.77	$ 16.33	$ 32.11	$ 10.04	$ 5.28	$ 15.32	$ 16.33	$ 31.65	$ (0.46)	(1.42)%
50	$ 9.43	$ 9.07	$ 18.49	$ 23.33	$ 41.83	$ 10.04	$ 7.55	$ 17.58	$ 23.33	$ 40.92	$ (0.91)	(2.18)%
75	$ 9.43	$ 13.60	$ 23.03	$ 35.00	$ 58.03	$ 10.04	$ 11.32	$ 21.36	$ 35.00	$ 56.35	$ (1.67)	(2.88)%
100	$ 9.43	$ 18.13	$ 27.56	$ 46.67	$ 74.23	$ 10.04	$ 15.09	$ 25.13	$ 46.67	$ 71.79	$ (2.43)	(3.28)%
105	$ 9.43	$ 19.04	$ 28.47	$ 49.00	$ 77.46	$ 10.04	$ 15.84	$ 25.88	$ 49.00	$ 74.88	$ (2.58)	(3.34)%
150	$ 9.43	$ 27.20	$ 36.62	$ 70.00	$ 106.62	$ 10.04	$ 22.64	$ 32.67	$ 70.00	$ 102.67	$ (3.95)	(3.71)%
200	$ 9.43	$ 36.26	$ 45.69	$ 93.33	$ 139.02	$ 10.04	$ 30.18	$ 40.22	$ 93.33	$ 133.55	$ (5.47)	(3.94)%
300	$ 9.43	$ 54.39	$ 63.82	$ 140.00	$ 203.82	$ 10.04	$ 45.27	$ 55.31	$ 140.00	$ 195.31	$ (8.51)	(4.18)%
Rg-1: Residential Firm Sales Service During Winter Months												
5	$ 9.43	$ 0.91	$ 10.34	$ 2.78	$ 13.12	$ 10.04	$ 0.75	$ 10.79	$ 2.78	$ 13.57	$ 0.46	3.48%
15	$ 9.43	$ 2.72	$ 12.15	$ 8.34	$ 20.49	$ 10.04	$ 2.26	$ 12.30	$ 8.34	$ 20.64	$ 0.15	0.74%
21	$ 9.43	$ 3.81	$ 13.24	$ 11.68	$ 24.92	$ 10.04	$ 3.17	$ 13.21	$ 11.68	$ 24.89	$ (0.03)	(0.12)%
35	$ 9.43	$ 6.35	$ 15.77	$ 19.47	$ 35.24	$ 10.04	$ 5.28	$ 15.32	$ 19.47	$ 34.79	$ (0.46)	(1.29)%
50	$ 9.43	$ 9.07	$ 18.49	$ 27.81	$ 46.31	$ 10.04	$ 7.55	$ 17.58	$ 27.81	$ 45.39	$ (0.91)	(1.97)%
75	$ 9.43	$ 13.60	$ 23.03	$ 41.72	$ 64.75	$ 10.04	$ 11.32	$ 21.36	$ 41.72	$ 63.07	$ (1.67)	(2.58)%
100	$ 9.43	$ 18.13	$ 27.56	$ 55.62	$ 83.18	$ 10.04	$ 15.09	$ 25.13	$ 55.62	$ 80.75	$ (2.43)	(2.92)%
105 avg.	$ 9.43	$ 19.04	$ 28.47	$ 58.41	$ 86.87	$ 10.04	$ 15.84	$ 25.88	$ 58.41	$ 84.29	$ (2.58)	(2.97)%
150	$ 9.43	$ 27.20	$ 36.62	$ 83.44	$ 120.06	$ 10.04	$ 22.64	$ 32.67	$ 83.44	$ 116.11	$ (3.95)	(3.29)%
200	$ 9.43	$ 36.26	$ 45.69	$ 111.25	$ 156.94	$ 10.04	$ 30.18	$ 40.22	$ 111.25	$ 151.47	$ (5.47)	(3.49)%
300	$ 9.43	$ 54.39	$ 63.82	$ 166.87	$ 230.69	$ 10.04	$ 45.27	$ 55.31	$ 166.87	$ 222.18	$ (8.51)	(3.69)%
Avg. Annual Residential Billing												
756	$ 113.15	$ 137.06	$ 250.21	$ 409.23	$ 659.45	$ 120.45	$ 114.08	$ 234.53	$ 409.23	$ 643.76	$ (15.68)	(2.38)%

Purchased Gas Adjustment/ Gas Cost Recovery Mechanism (continued)

5. SURCHARGE COSTS: The surcharge costs, which include FERC approved surcharges for gas purchases or transportation by pipelines or other suppliers shall be computed by dividing the company's total costs associated with surcharges for the period by the total forecasted weather normal sales therms for the program year then multiplied by the total weather normal natural gas therm usage forecasted for sales customers participating in the Fixed Gas Bill Program to arrive at a surcharge cost associated with the Fixed Gas Bill Program. Surcharge costs to be applied to the Fixed Gas Bill Program shall be accounted for separately from natural gas costs in the company's natural gas portfolio.

   Program rates are on a per customer basis and shall not change for the duration of the program contract period. Rates will be recalculated at the time of renewal of contracts of customers participating in the Fixed Gas Bill Program.

   Administrative Charge Percentage: The program administrative charge shall be a premium charged to the customer in accordance with 7e of tariff schedule X-615.

6. RECONCILIATION OF GAS COSTS: Gas Costs: Monthly, the cost of gas and recoveries shall be booked separately from the Purchased Gas Adjustment/ Gas Cost Recovery Mechanism as found on Schedule X-220. Customers participating in the Fixed Gas Bill Program will not be subject to natural gas cost reconciliation adjustments.

   Customers not participating in the Fixed Gas Bill Program will not be affected by any natural gas reconciliation amount from this program.

7. ~~REQUIRED APPROVALS AND REPORTS: The company shall file with the PSCW such reports as may be required by the Commission to monitor the operation of the Fixed Gas Bill Program.~~

7~~8~~. REFUND PROVISION Customers participating in the Fixed Gas Bill Program shall not be eligible for wholesale refunds.

General Conditions of Delivery
(continued)

7. Rates applied to customers weather normalized consumption data to determine the customer's monthly fixed bill amount shall include:
    a. all the fixed and variable marginal rates applicable for their corresponding sales rate class schedule and tariff schedule X-100 per firm sales service;
    b. plus a factor for gas costs as provided in the most recent gas supply plan or purchased gas adjustment affecting peak demand, annual demand and FERC authorized surcharges;
    c. plus a charge for commodity natural gas costs that shall be fixed by the company prior to the start of the program year;
    d. less any efficiency reward;
    e. plus an administrative charge of 7% of the customer's total charges before sales tax.
    f. Total costs for one year's participation in the Fixed Gas Bill Program arrived at by applying rates to weather normalized consumption plus all appropriate fixed charges shall be divided by twelve to arrive at the customer's monthly fixed bill amount before sales tax.

8. Customers participating in the Fixed Gas Bill Program shall not be eligible for pipeline refunds, and refunds or credits due to the Company's Gas Cost Recovery Mechanism. However, participating customers may be eligible to receive a credit or refund as determined by the Company ~~and approved by the PSCW~~ for any profitability refund for the November to October program year.

9. Early termination/cancellation of customers from the Fixed Gas Bill Program shall be subject to the rate switching provisions as found in paragraph 2 on tariff schedule X-605.

10. The company will use reasonable diligence to provide an uninterrupted supply of gas, but it shall not be liable for interruptions, deficiencies, or imperfections of service. The company may temporarily suspend the delivery of service when necessary for the purpose of making repairs, changes, and improvements upon any part of its system without compensation to the customer.

Bundled Gas Revenue Summary for the 2015 Test Year

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 and Rely-A-Bill								
WG Residential (Rg-1)	437,023,375	$ 154,649,226	$ 250,574,945	$ 405,224,171	$ 13,107,021	$ 418,331,192	3.23%	8.48%
WG Rely-A-Bill (Rf-1)	-	$ 1,018,350		$ 1,018,350	$ 65,700	$ 1,084,050	6.45%	6.45%
Subtotal	437,023,375	$ 155,667,576	$ 250,574,945	$ 406,242,521	$ 13,172,721	$ 419,415,242	3.24%	8.46%
Commercial & Industrial, g-1 (0 to 3,999)								
WG Firm Comm. Ind. (Fg-1)	51,598,189	$ 15,595,662	$ 29,902,105	$ 45,497,767	$ 1,375,681	$ 46,873,448	3.02%	8.82%
WG Agricultural Seasonal Use (Ag-1)	132,531	$ 32,656	$ 63,883	$ 96,540	$ 3,056	$ 99,596	3.17%	9.36%
WG Natural Gas Vehicles 1 (NGV-1)	1,914	$ 518	$ 936	$ 1,453	$ 47	$ 1,500	3.24%	9.10%
WG Ornamental Lighting (OL)	-	$ -	$ -	$ -	$ -	$ -	0.00%	0.00%
WG Transport Commercial (Tf-1)	16,431	$ 16,203	$ (24)	$ 16,179	$ 802	$ 16,981	4.96%	4.95%
Subtotal	51,749,065	15,645,039	$ 29,966,901	45,611,939	1,379,586	46,991,526	3.02%	8.82%
Commercial & Industrial, g-2 (4,000 to 39,999)								
WG Firm Comm. Ind. (Fg-2)	141,089,584	$ 27,628,805	$ 80,633,061	$ 108,261,866	$ (634,903)	$ 107,626,963	(0.59)%	(2.30)%
WG Agricultural Seasonal Use (Ag-2)	1,158,492	$ 216,179	$ 556,875	$ 773,055	$ (5,213)	$ 767,841	(0.67)%	(2.41)%
WG Natural Gas Vehicles 2 (NGV-2)	403,223	$ 73,512	$ 200,739	$ 274,250	$ (1,815)	$ 272,436	(0.66)%	(2.47)%
WG Transport Commercial 2 (Tf-2)	6,640,698	$ 1,117,373	$ (9,563)	$ 1,107,810	$ 141,447	$ 1,249,257	12.77%	12.66%
Subtotal	149,291,997	29,035,869	$ 81,381,112	110,416,981	(500,484)	109,916,497	(0.45)%	(1.72)%
Commercial & Industrial, g-3 (40,000 to 99,999)								
WG Firm Comm. Ind. (Fg-3)	39,307,234	$ 6,570,653	$ 22,295,783	$ 28,866,435	$ (286,588)	$ 28,579,847	(0.99)%	(4.36)%
WG Agricultural Seasonal Use (Ag-3)	1,066,372	$ 181,091	$ 528,324	$ 709,415	$ (7,677)	$ 701,738	(1.08)%	(4.24)%
WG Natural Gas Vehicles 3 (NGV-3)	311,597	$ 51,747	$ 153,517	$ 205,264	$ (2,284)	$ 202,981	(1.11)%	(4.41)%
WG Inter. Comm. Ind. (Ig-3)	213,917	$ 34,545	$ 101,563	$ 136,108	$ (1,599)	$ 134,509	(1.18)%	(4.63)%
WG Transport Commercial 3 (Tf-3)	19,876,769	$ 2,639,893	$ (28,623)	$ 2,611,270	$ 316,149	$ 2,927,419	12.11%	11.98%
Subtotal	60,775,889	9,477,929	$ 23,050,564	32,528,493	18,001	32,546,493	0.06%	0.19%
Commercial & Industrial g-4 (100,000 to 499,999)								
WG Firm Comm. Ind. (Fg-4)	21,119,158	$ 3,052,374	$ 11,730,077	$ 14,782,451	$ (287,221)	$ 14,495,230	(1.94)%	(9.41)%
WG Agricultural Seasonal Use (Ag-4)	701,999	$ 108,104	$ 341,197	$ 449,301	$ (9,547)	$ 439,754	(2.12)%	(8.83)%
WG Inter. Comm. Ind. (Ig-4)	2,669,435	$ 362,013	$ 1,267,388	$ 1,629,401	$ (36,304)	$ 1,593,096	(2.23)%	(10.03)%
WG Transport Commercial 4 (Tf-4)	84,253,794	$ 7,643,861	$ (121,328)	$ 7,522,533	$ 921,444	$ 8,443,977	12.25%	12.05%
Subtotal	108,744,386	11,166,352	$ 13,217,334	24,383,685	588,372	24,972,057	2.41%	5.27%
Commercial & Industrial g-5 (500,000 to 999,999)								
WG Firm Comm. Ind. (Fg-5)	3,860,244	$ 430,145	$ 2,087,329	$ 2,517,474	$ (26,636)	$ 2,490,839	(1.06)%	(6.19)%
WG Agricultural Seasonal Use (Ag-5)	-	$ -	$ -	$ -	$ -	$ -	0.00%	0.00%
WG Inter. Comm. Ind. (Ig-5)	2,695,227	$ 279,986	$ 1,279,634	$ 1,559,620	$ (18,597)	$ 1,541,023	(1.19)%	(6.64)%
WG Transport Commercial 5 (Tf-5)	51,263,024	$ 4,004,937	$ (73,820)	$ 3,931,117	$ 440,862	$ 4,371,979	11.21%	11.01%
Subtotal	57,818,495	4,715,069	$ 3,293,143	8,008,212	395,629	8,403,841	4.94%	8.39%
Commercial & Industrial g-6 (1,000,000 to 7,999,999)								
WG Firm Comm. Ind. (Fg-6)	1,566,779	$ 131,348	$ 851,113	$ 982,461	$ (11,037)	$ 971,424	(1.12)%	(8.40)%
WG Inter. Comm. Ind. (Ig-6)	5,958,076	$ 506,029	$ 2,828,761	$ 3,334,790	$ (40,185)	$ 3,294,605	(1.21)%	(7.94)%
WG Transport Commercial 6 (Tf-6)	224,131,864	$ 10,170,155	$ (322,756)	$ 9,847,398	$ 1,982,221	$ 11,829,620	20.13%	19.49%
Subtotal	231,656,719	10,807,532	$ 3,357,118	14,164,650	1,930,999	16,095,649	13.63%	17.87%
Commercial & Industrial, g-7 (8,000,000 and over)								
WG Transport Commercial 7 (Tf-7)	8,778,126	$ 400,482	$ (12,641)	$ 387,841	$ 36,267	$ 424,108	9.35%	9.06%
Subtotal	8,778,126	400,482	$ (12,641)	387,841	36,267	424,108	9.35%	9.06%
Power Generators and Special Contracts	341,357,927	$ 7,120,938	$ (36,486)	$ 7,084,452	$ 75,557	$ 7,160,009	1.07%	1.06%
Subtotal	341,357,927	7,120,938	$ (36,486)	7,084,452	75,557	7,160,009	1.07%	1.06%
Total Gas Sales Revenues	1,447,195,979	$ 244,036,785	$ 404,791,990	$ 648,828,775	$ 17,096,648	$ 665,925,423	2.64%	7.01%
Plus:								
Other Gas Revenue				$ 4,593,240		$ 4,593,240		
Total Gas Operating Revenue				$ 653,422,015		$ 670,518,663	2.62%	

Gas Rate Comparison
Present and Authorized 2015 Gas Rates

	Present Margin	Authorized Margin
Residential		
Daily Basic Distribution Charge (Rg-1, Rt-1)	$ 0.31	$ 0.33
Transportation Administrative Charge (Rt-1)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Rg-1, Rt-1)	$ 0.1638	$ 0.2050
Daily Balancing Charge (Rg-1, Rt-1)	$ 0.0013	$ 0.0018
Competitive Supply Charge (Rg-1)	$ 0.0459	$ 0.0250
Peak Day Backup Charge (Rg-1)	$ 0.0004	$ 0.0004
Commercial (0 to 3,999)		
Daily Basic Distribution Charge (Fg-1, Ag-1, NGV-1, Tf-1)	$ 0.31	$ 0.33
Transportation Administrative Charge (Tf-1)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Fg-1, Ag-1, NGV-1, Tf-1)	$ 0.1638	$ 0.2050
Daily Balancing Charge (Fg-1, Ag-1, NGV-1, Tf-1)	$ 0.0013	$ 0.0018
Competitive Supply Charge (Fg-1, NGV-1, Ag-1)	$ 0.0459	$ 0.0250
Peak Day Backup Charge (Fg-1, NGV-1, Ag-1)	$ 0.0004	$ 0.0004
Commercial (4,000 to 39,999)		
Daily Basic Distribution Charge (Fg-2, Ag-2, NGV-2, Tf-2)	$ 0.85	$ 0.85
Transportation Administrative Charge (Tf-2)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Fg-2, Ag-2, NGV-2, Tf-2)	$ 0.1231	$ 0.1439
Daily Balancing Charge (Fg-2, Ag-2, NGV-2, Tf-2)	$ 0.0013	$ 0.0018
Competitive Supply Charge (Fg-2, Ag-2, NGV-2)	$ 0.0453	$ 0.0195
Peak Day Backup Charge (Fg-2, Ag-2, NGV-2)	$ 0.0003	$ 0.0003
Commercial (40,000 to 99,999)		
Daily Basic Distribution Charge (Fg-3, Ag-3, NGV-3, Tf-3)	$ 5.80	$ 6.00
Transportation Administrative Charge (Tf-3)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Fg-3, Ag-3, NGV-3, Tf-3)	$ 0.0884	$ 0.1027
Daily Balancing Charge (Fg-3, Ag-3, NGV-3, Tf-3)	$ 0.0013	$ 0.0018
Competitive Supply Charge (Fg-3, Ag-3, NGV-3)	$ 0.0421	$ 0.0188
Peak Day Backup Charge (Fg-3, Ag-3, NGV-3)	$ 0.0003	$ 0.0003

Gas Rate Comparison
Present and Authorized 2015 Gas Rates

	Present Margin	Authorized Margin
Commercial (100,000 to 499,999)		
Daily Basic Distribution Charge (Fg-4, Ag-4, Ig-4, Tf-4)	$ 15.00	$ 15.00
Transportation Administrative Charge (Tf-4)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Fg-4, Ag-4, Ig-4, Tf-4)	$ 0.0643	$ 0.0746
Daily Balancing Charge (Fg-4, Ag-4, Ig-4, Tf-4)	$ 0.0013	$ 0.0018
Competitive Supply Charge (Fg-4, Ag-4, Ig-4)	$ 0.0413	$ 0.0169
Peak Day Backup Charge (Fg-4, Ag-4)	$ 0.0003	$ 0.0003
Commercial (500,000 to 999,999)		
Daily Basic Distribution Charge (Fg-5, Ag-5, Ig-5, Tf-5)	$ 45.00	$ 45.00
Transportation Administrative Charge (Tf-5)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Fg-5, Ag-5, Ig-5, Tf-5)	$ 0.0534	$ 0.0615
Daily Balancing Charge (Fg-5, Ag-5, Ig-5, Tf-5)	$ 0.0013	$ 0.0018
Competitive Supply Charge (Fg-5, Ag-5, Ig-5)	$ 0.0309	$ 0.0154
Peak Day Backup Charge (Fg-5, Ag-5)	$ 0.0003	$ 0.0003
Commercial (1,000,000 to 7,999,999)		
Daily Basic Distribution Charge (Fg-6, Ig-6, Tf-6)	$ 85.00	$ 85.00
Transportation Administrative Charge (Tf-6)	$ 2.00	$ 2.00
Volumetric Charges:		
Demand Charge (Fg-6, Ig-6, Tf-6)	$ 0.0026	$ 0.0040
Distribution Service Charge (Fg-6, Ig-6, Tf-6)	$ 0.0266	$ 0.0324
Daily Balancing Charge (Fg-6, Ig-6, Tf-6)	$ 0.0013	$ 0.0018
Competitive Supply Charge (Fg-6, Ig-6)	$ 0.0309	$ 0.0150
Peak Day Backup Charge (Fg-6)	$ 0.0003	$ 0.0002
Commercial (8,000,000 +)		
Daily Basic Distribution Charge (Fg-7, Ig-7, Tf-7)	$ 450.00	$ 450.00
Transportation Administrative Charge (Tf-7)	$ 2.00	$ 2.00
Volumetric Charges:		
Demand Charge (Fg-7, Ig-7, Tf-7)	$ 0.0018	$ 0.0031
Distribution Service Charge (Fg-7, Ig-7, Tf-7)	$ 0.0187	$ 0.0174
Daily Balancing Charge (Fg-7, Ig-7, Tf-7)	$ 0.0013	$ 0.0018
Competitive Supply Charge (Fg-7, Ig-7)	$ 0.0220	$ 0.0150
Peak Day Backup Charge (Fg-7)	$ 0.0003	$ 0.0002

Gas Rate Comparison
Present and Authorized 2015 Gas Rates

		Present Margin	Authorized Margin
Base Gas Cost Rates:			
Average Peak Day Demand Costs - Volumetric		$ 0.1183	$ 0.1194
Average Annual Demand Costs		$ 0.0331	$ 0.0280
Average Commodity Costs		$ 0.3654	$ 0.4482
Lost and Unaccounted For $/Therm		$ (0.0011)	$ (0.0014)
Daily Cashout Rates:			
Competitive Supply		$ 0.0336	$ 0.0157
Peak Day Backup		$ 0.0003	$ 0.0002
Act 141 Volumetric Distribution Rates 1/			
Residential		$ 0.0111	$ 0.0079
Commercial G-1	(0 to 3,999)	$ 0.0167	$ 0.0122
Commercial G-2	(4,000 to 39,999)	$ 0.0167	$ 0.0122
Commercial G-3	(40,000 to 99,999)	$ 0.0167	$ 0.0122
Commercial G-4	(100,000 to 499,999)	$ 0.0167	$ 0.0122
Commercial G-5	(500,000 to 999,999)	$ 0.0167	$ 0.0122
Commercial G-6	(1,000,000 to 7,999,999)	$ 0.0001	$ 0.0001
Commercial G-7	(8,000,000 +)	$ 0.0001	$ 0.0001

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

	Present Margin	Authorized Margin
Electric Generation Special Contract Service		
Fixed Daily Charges		
Pt-10	$ 10,237.00	$ 10,237.00
Volumetric Charges		
Pt-10	$ 0.0016	$ 0.0016
Demand Charge:		
Pt-10	$ 0.0024	$ 0.0024

WGC 2015 Residential Monthly Bill Impact Analysis

Gas Costs	Summer	Winter
Firm Service	0.4748	0.5942

Monthly Use Therms		Present Customer Charge	Current Admin. & Distribut'n Charges	Total Monthly Cost	Gas Costs	Total Costs	Authorized Admin. & Customer Charges	Authorized Admin. & Distribut'n Charges	Authorized Total Monthly Cost	Gas Costs	Total Costs	Monthly Bill Increase (Decrease)	Monthly Percent Increase (Decrease)
Rg-1: Residential Firm Sales Service During Summer Months													
5		$ 9.43	$ 1.06	$ 10.49	$ 2.37	$ 12.86	$ 10.04	$ 1.16	$ 11.20	$ 2.37	$ 13.57	$ 0.71	5.54%
15		$ 9.43	$ 3.17	$ 12.60	$ 7.12	$ 19.72	$ 10.04	$ 3.48	$ 13.52	$ 7.12	$ 20.64	$ 0.92	4.67%
23	avg.	$ 9.43	$ 4.86	$ 14.29	$ 10.92	$ 25.21	$ 10.04	$ 5.34	$ 15.38	$ 10.92	$ 26.30	$ 1.09	4.31%
35		$ 9.43	$ 7.40	$ 16.83	$ 16.62	$ 33.45	$ 10.04	$ 8.13	$ 18.16	$ 16.62	$ 34.78	$ 1.34	4.00%
50		$ 9.43	$ 10.57	$ 20.00	$ 23.74	$ 43.74	$ 10.04	$ 11.61	$ 21.65	$ 23.74	$ 45.39	$ 1.65	3.77%
75		$ 9.43	$ 15.86	$ 25.28	$ 35.61	$ 60.89	$ 10.04	$ 17.42	$ 27.45	$ 35.61	$ 63.06	$ 2.17	3.56%
100		$ 9.43	$ 21.14	$ 30.57	$ 47.48	$ 78.05	$ 10.04	$ 23.22	$ 33.26	$ 47.48	$ 80.74	$ 2.69	3.44%
108		$ 9.43	$ 22.83	$ 32.26	$ 51.28	$ 83.54	$ 10.04	$ 25.08	$ 35.12	$ 51.28	$ 86.39	$ 2.85	3.42%
150		$ 9.43	$ 31.71	$ 41.14	$ 71.22	$ 112.36	$ 10.04	$ 34.83	$ 44.87	$ 71.22	$ 116.08	$ 3.73	3.32%
200		$ 9.43	$ 42.28	$ 51.71	$ 94.96	$ 146.66	$ 10.04	$ 46.44	$ 56.48	$ 94.96	$ 151.43	$ 4.77	3.25%
300		$ 9.43	$ 63.42	$ 72.85	$ 142.43	$ 215.28	$ 10.04	$ 69.66	$ 79.70	$ 142.43	$ 222.13	$ 6.85	3.18%
Rg-1: Residential Firm Sales Service During Winter Months													
5		$ 9.43	$ 1.06	$ 10.49	$ 2.97	$ 13.46	$ 10.04	$ 1.16	$ 11.20	$ 2.97	$ 14.17	$ 0.71	5.29%
15		$ 9.43	$ 3.17	$ 12.60	$ 8.91	$ 21.51	$ 10.04	$ 3.48	$ 13.52	$ 8.91	$ 22.43	$ 0.92	4.28%
23		$ 9.43	$ 4.86	$ 14.29	$ 13.67	$ 27.96	$ 10.04	$ 5.34	$ 15.38	$ 13.67	$ 29.04	$ 1.09	3.89%
35		$ 9.43	$ 7.40	$ 16.83	$ 20.80	$ 37.62	$ 10.04	$ 8.13	$ 18.16	$ 20.80	$ 38.96	$ 1.34	3.55%
50		$ 9.43	$ 10.57	$ 20.00	$ 29.71	$ 49.71	$ 10.04	$ 11.61	$ 21.65	$ 29.71	$ 51.36	$ 1.65	3.32%
75		$ 9.43	$ 15.86	$ 25.28	$ 44.56	$ 69.85	$ 10.04	$ 17.42	$ 27.45	$ 44.56	$ 72.02	$ 2.17	3.10%
100		$ 9.43	$ 21.14	$ 30.57	$ 59.42	$ 89.99	$ 10.04	$ 23.22	$ 33.26	$ 59.42	$ 92.68	$ 2.69	2.99%
108	avg.	$ 9.43	$ 22.83	$ 32.26	$ 64.17	$ 96.43	$ 10.04	$ 25.08	$ 35.12	$ 64.17	$ 99.29	$ 2.85	2.96%
150		$ 9.43	$ 31.71	$ 41.14	$ 89.13	$ 130.27	$ 10.04	$ 34.83	$ 44.87	$ 89.13	$ 134.00	$ 3.73	2.86%
200		$ 9.43	$ 42.28	$ 51.71	$ 118.84	$ 170.55	$ 10.04	$ 46.44	$ 56.48	$ 118.84	$ 175.32	$ 4.77	2.80%
300		$ 9.43	$ 63.42	$ 72.85	$ 178.26	$ 251.11	$ 10.04	$ 69.66	$ 79.70	$ 178.26	$ 257.96	$ 6.85	2.73%
Avg. Annual Residential Billing													
786		$ 113.15	$ 166.16	$ 279.31	$ 450.56	$ 729.87	$ 120.45	$ 182.51	$ 302.96	$ 450.56	$ 753.52	$ 23.65	3.24%

Bundled Gas Revenue Summary for the 2016 Test Year

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 and Rely-A-Bill								
WG Residential (Rg-1)	437,023,375	$ 167,756,247	$ 250,574,945	$ 418,331,192	$ 12,236,655	$ 430,567,846	2.93%	7.29%
WG Rely-A-Bill (Rf-1)	-	$ 1,084,050		$ 1,084,050	$ -	$ 1,084,050	0.00%	0.00%
Subtotal	437,023,375	$ 168,840,297	$ 250,574,945	$ 419,415,242	$ 12,236,655	$ 431,651,896	2.92%	7.25%
Commercial & Industrial, g-1 (0 to 3,999)								
WG Firm Comm. Ind. (Fg-1)	51,598,189	$ 16,971,343	$ 29,902,105	$ 46,873,448	$ 1,444,749	$ 48,318,198	3.08%	8.51%
WG Agricultural Seasonal Use (Ag-1)	132,531	$ 35,712	$ 63,883	$ 99,596	$ 3,711	$ 103,306	3.73%	10.39%
WG Natural Gas Vehicles 1 (NGV-1)	1,914	$ 565	$ 936	$ 1,500	$ 54	$ 1,554	3.57%	9.49%
WG Ornamental Lighting (OL)	-	$ -	$ -	$ -	$ -	$ -	0.00%	0.00%
WG Transport Commercial (Tf-1)	16,431	$ 17,005	$ (24)	$ 16,981	$ 460	$ 17,442	2.71%	2.71%
Subtotal	51,749,065	17,024,625	$ 29,966,901	46,991,526	1,448,974	48,440,500	3.08%	8.51%
Commercial & Industrial, g-2 (4,000 to 39,999)								
WG Firm Comm. Ind. (Fg-2)	141,089,584	$ 26,993,902	$ 80,633,061	$ 107,626,963	$ 3,188,625	$ 110,815,588	2.96%	11.81%
WG Agricultural Seasonal Use (Ag-2)	1,158,492	$ 210,966	$ 556,875	$ 767,841	$ 26,182	$ 794,023	3.41%	12.41%
WG Natural Gas Vehicles 2 (NGV-2)	403,223	$ 71,697	$ 200,739	$ 272,436	$ 9,113	$ 281,549	3.34%	12.71%
WG Transport Commercial 2 (Tf-2)	6,640,698	$ 1,258,820	$ (9,563)	$ 1,249,257	$ 150,080	$ 1,399,337	12.01%	11.92%
Subtotal	149,291,997	28,535,385	$ 81,381,112	109,916,497	3,373,999	113,290,496	3.07%	11.82%
Commercial & Industrial, g-3 (40,000 to 99,999)								
WG Firm Comm. Ind. (Fg-3)	39,307,234	$ 6,284,064	$ 22,295,783	$ 28,579,847	$ 589,609	$ 29,169,455	2.06%	9.38%
WG Agricultural Seasonal Use (Ag-3)	1,066,372	$ 173,414	$ 528,324	$ 701,738	$ 15,996	$ 717,733	2.28%	9.22%
WG Natural Gas Vehicles 3 (NGV-3)	311,597	$ 49,463	$ 153,517	$ 202,981	$ 4,674	$ 207,655	2.30%	9.45%
WG Inter. Comm. Ind. (Ig-3)	213,917	$ 32,946	$ 101,563	$ 134,509	$ 3,209	$ 137,718	2.39%	9.74%
WG Transport Commercial 3 (Tf-3)	19,876,769	$ 2,956,042	$ (28,623)	$ 2,927,419	$ 298,152	$ 3,225,571	10.18%	10.09%
Subtotal	60,775,889	9,495,929	$ 23,050,564	32,546,493	911,638	33,458,132	2.80%	9.60%
Commercial & Industrial g-4 (100,000 to 499,999)								
WG Firm Comm. Ind. (Fg-4)	21,119,158	$ 2,765,153	$ 11,730,077	$ 14,495,230	$ 249,206	$ 14,744,436	1.72%	9.01%
WG Agricultural Seasonal Use (Ag-4)	701,999	$ 98,557	$ 341,197	$ 439,754	$ 8,284	$ 448,037	1.88%	8.40%
WG Inter. Comm. Ind. (Ig-4)	2,669,435	$ 325,708	$ 1,267,388	$ 1,593,096	$ 31,499	$ 1,624,596	1.98%	9.67%
WG Transport Commercial 4 (Tf-4)	84,253,794	$ 8,565,305	$ (121,328)	$ 8,443,977	$ 994,195	$ 9,438,172	11.77%	11.61%
Subtotal	108,744,386	11,754,723	$ 13,217,334	24,972,057	1,283,184	26,255,241	5.14%	10.92%
Commercial & Industrial g-5 (500,000 to 999,999)								
WG Firm Comm. Ind. (Fg-5)	3,860,244	$ 403,509	$ 2,087,329	$ 2,490,839	$ 27,408	$ 2,518,246	1.10%	6.79%
WG Agricultural Seasonal Use (Ag-5)	-	$ -	$ -	$ -	$ -	$ -	0.00%	0.00%
WG Inter. Comm. Ind. (Ig-5)	2,695,227	$ 261,389	$ 1,279,634	$ 1,541,023	$ 19,136	$ 1,560,159	1.24%	7.32%
WG Transport Commercial 5 (Tf-5)	51,263,024	$ 4,445,799	$ (73,820)	$ 4,371,979	$ 363,967	$ 4,735,947	8.33%	8.19%
Subtotal	57,818,495	5,110,698	$ 3,293,143	8,403,841	410,511	8,814,352	4.88%	8.03%
Commercial & Industrial g-6 (1,000,000 to 7,999,999)								
WG Firm Comm. Ind. (Fg-6)	1,566,779	$ 120,311	$ 851,113	$ 971,424	$ 10,341	$ 981,765	1.06%	8.59%
WG Inter. Comm. Ind. (Ig-6)	5,958,076	$ 465,844	$ 2,828,761	$ 3,294,605	$ 39,323	$ 3,333,928	1.19%	8.44%
WG Transport Commercial 6 (Tf-6)	224,131,864	$ 12,152,376	$ (322,756)	$ 11,829,620	$ 1,479,270	$ 13,308,890	12.50%	12.17%
Subtotal	231,656,719	12,738,531	$ 3,357,118	16,095,649	1,528,934	17,624,583	9.50%	12.00%
Commercial & Industrial, g-7 (8,000,000 and over)								
WG Transport Commercial 7 (Tf-7)	8,778,126	$ 436,749	$ (12,641)	$ 424,108	$ 61,447	$ 485,555	14.49%	14.07%
Subtotal	8,778,126	436,749	$ (12,641)	424,108	61,447	485,555	14.49%	14.07%
Power Generators and Special Contracts	341,357,927	$ 7,196,495	$ (36,486)	$ 7,160,009	$ 144,236	$ 7,304,245	2.01%	2.00%
Subtotal	341,357,927	7,196,495	$ (36,486)	7,160,009	144,236	7,304,245	2.01%	2.00%
Total Gas Sales Revenues	1,447,195,979	$ 261,133,433	$ 404,791,990	$ 665,925,423	$ 21,399,578	$ 687,325,001	3.21%	8.19%
Plus:								
Other Gas Revenue				$ 4,593,240		$ 4,593,240		
Total Gas Operating Revenue				$ 670,518,663		$ 691,918,241	3.19%	

Gas Margin Rate Comparison
2015 and 2016 Authorized Rates

	2015 Margin Rates	2016 Authorized Margin
Residential		
Daily Basic Distribution Charge (Rg-1, Rt-1)	$ 0.33	$ 0.33
Transportation Administrative Charge (Rt-1)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Rg-1, Rt-1)	$ 0.2050	$ 0.2330
Daily Balancing Charge (Rg-1, Rt-1)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Rg-1)	$ 0.0250	$ 0.0250
Peak Day Backup Charge (Rg-1)	$ 0.0004	$ 0.0004
Commercial (0 to 3,999)		
Daily Basic Distribution Charge (Fg-1, Ag-1, NGV-1, Tf-1)	$ 0.33	$ 0.33
Transportation Administrative Charge (Tf-1)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Fg-1, Ag-1, NGV-1, Tf-1)	$ 0.2050	$ 0.2330
Daily Balancing Charge (Fg-1, Ag-1, NGV-1, Tf-1)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Fg-1, NGV-1, Ag-1)	$ 0.0250	$ 0.0250
Peak Day Backup Charge (Fg-1, NGV-1, Ag-1)	$ 0.0004	$ 0.0004
Commercial (4,000 to 39,999)		
Daily Basic Distribution Charge (Fg-2, Ag-2, NGV-2, Tf-2)	$ 0.85	$ 0.85
Transportation Administrative Charge (Tf-2)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Fg-2, Ag-2, NGV-2, Tf-2)	$ 0.1439	$ 0.1665
Daily Balancing Charge (Fg-2, Ag-2, NGV-2, Tf-2)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Fg-2, Ag-2, NGV-2)	$ 0.0195	$ 0.0195
Peak Day Backup Charge (Fg-2, Ag-2, NGV-2)	$ 0.0003	$ 0.0003
Commercial (40,000 to 99,999)		
Daily Basic Distribution Charge (Fg-3, Ag-3, NGV-3, Tf-3)	$ 6.00	$ 6.00
Transportation Administrative Charge (Tf-3)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Fg-3, Ag-3, NGV-3, Tf-3)	$ 0.1027	$ 0.1177
Daily Balancing Charge (Fg-3, Ag-3, NGV-3, Tf-3)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Fg-3, Ag-3, NGV-3)	$ 0.0188	$ 0.0188
Peak Day Backup Charge (Fg-3, Ag-3, NGV-3)	$ 0.0003	$ 0.0003

Gas Margin Rate Comparison
2015 and 2016 Authorized Rates

	2015 Margin Rates	2016 Authorized Margin
Commercial (100,000 to 499,999)		
Daily Basic Distribution Charge (Fg-4, Ag-4, Ig-4, Tf-4)	$ 15.00	$ 15.00
Transportation Administrative Charge (Tf-4)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Fg-4, Ag-4, Ig-4, Tf-4)	$ 0.0746	$ 0.0864
Daily Balancing Charge (Fg-4, Ag-4, Ig-4, Tf-4)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Fg-4, Ag-4, Ig-4)	$ 0.0169	$ 0.0169
Peak Day Backup Charge (Fg-4, Ag-4)	$ 0.0003	$ 0.0003
Commercial (500,000 to 999,999)		
Daily Basic Distribution Charge (Fg-5, Ag-5, Ig-5, Tf-5)	$ 45.00	$ 45.00
Transportation Administrative Charge (Tf-5)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Fg-5, Ag-5, Ig-5, Tf-5)	$ 0.0615	$ 0.0686
Daily Balancing Charge (Fg-5, Ag-5, Ig-5, Tf-5)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Fg-5, Ag-5, Ig-5)	$ 0.0154	$ 0.0154
Peak Day Backup Charge (Fg-5, Ag-5)	$ 0.0003	$ 0.0003
Commercial (1,000,000 to 7,999,999)		
Daily Basic Distribution Charge (Fg-6, Ig-6, Tf-6)	$ 85.00	$ 85.00
Transportation Administrative Charge (Tf-6)	$ 2.00	$ 2.00
Volumetric Charges:		
Demand Charge (Fg-6, Ig-6, Tf-6)	$ 0.0040	$ 0.0040
Distribution Service Charge (Fg-6, Ig-6, Tf-6)	$ 0.0324	$ 0.0390
Daily Balancing Charge (Fg-6, Ig-6, Tf-6)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Fg-6, Ig-6)	$ 0.0150	$ 0.0150
Peak Day Backup Charge (Fg-6)	$ 0.0002	$ 0.0002
Commercial (8,000,000 +)		
Daily Basic Distribution Charge (Fg-7, Ig-7, Tf-7)	$ 450.00	$ 450.00
Transportation Administrative Charge (Tf-7)	$ 2.00	$ 2.00
Volumetric Charges:		
Demand Charge (Fg-7, Ig-7, Tf-7)	$ 0.0031	$ 0.0031
Distribution Service Charge (Fg-7, Ig-7, Tf-7)	$ 0.0174	$ 0.0244
Daily Balancing Charge (Fg-7, Ig-7, Tf-7)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Fg-7, Ig-7)	$ 0.0150	$ 0.0150
Peak Day Backup Charge (Fg-7)	$ 0.0002	$ 0.0002

Gas Margin Rate Comparison
2015 and 2016 Authorized Rates

	2015 Margin Rates	2016 Authorized Margin
Base Gas Cost Rates:		
Average Peak Day Demand Costs - Volumetric	$ 0.1194	$ 0.1194
Average Annual Demand Costs	$ 0.0280	$ 0.0280
Average Commodity Costs	$ 0.4482	$ 0.4482
Lost and Unaccounted For $/Therm	$ (0.0014)	$ (0.0014)
Daily Cashout Rates:		
Competitive Supply	$ 0.0157	$ 0.0157
Peak Day Backup	$ 0.0002	$ 0.0002
Act 141 Volumetric Distribution Rates 1/		
Residential	$ 0.0079	$ 0.0079
Commercial G-1 (0 to 3,999)	$ 0.0122	$ 0.0122
Commercial G-2 (4,000 to 39,999)	$ 0.0122	$ 0.0122
Commercial G-3 (40,000 to 99,999)	$ 0.0122	$ 0.0122
Commercial G-4 (100,000 to 499,999)	$ 0.0122	$ 0.0122
Commercial G-5 (500,000 to 999,999)	$ 0.0122	$ 0.0122
Commercial G-6 (1,000,000 to 7,999,999)	$ 0.0001	$ 0.0001
Commercial G-7 (8,000,000 +)	$ 0.0001	$ 0.0001

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

Electric Generation Special Contract Service		
Fixed Daily Charges		
Pt-10	$ 10,237.00	$ 10,237.00
Volumetric Charges		
Pt-10	$ 0.0016	$ 0.0016
Demand Charge:		
Pt-10	$ 0.0024	$ 0.0024

WGC 2015 and 2016 Residential Monthly Bill Impact Analysis

Gas Costs	Summer	Winter
Firm Service	0.4748	0.5942

		2015					2016						
Monthly Use Therms		**Present Customer Charge**	**Current Admin. & Distribut'n Charges**	**Total Monthly Cost**	**Gas Costs**	**Total Costs**	**Authorized Admin. & Customer Charges**	**Authorized Admin. & Distribut'n Charges**	**Authorized Total Monthly Cost**	**Gas Costs**	**Total Costs**	**Monthly Bill Increase (Decrease)**	**Monthly Percent Increase (Decrease)**
Rg-1: Residential Firm Sales Service During Summer Months													
5		$ 10.04	$ 1.16	$ 11.20	$ 2.37	$ 13.57	$ 10.04	$ 1.30	$ 11.34	$ 2.37	$ 13.71	$ 0.14	1.03%
15		$ 10.04	$ 3.48	$ 13.52	$ 7.12	$ 20.64	$ 10.04	$ 3.90	$ 13.94	$ 7.12	$ 21.06	$ 0.42	2.03%
23	avg.	$ 10.04	$ 5.34	$ 15.38	$ 10.92	$ 26.30	$ 10.04	$ 5.98	$ 16.02	$ 10.92	$ 26.94	$ 0.64	2.45%
35		$ 10.04	$ 8.13	$ 18.16	$ 16.62	$ 34.78	$ 10.04	$ 9.11	$ 19.14	$ 16.62	$ 35.76	$ 0.98	2.82%
50		$ 10.04	$ 11.61	$ 21.65	$ 23.74	$ 45.39	$ 10.04	$ 13.01	$ 23.05	$ 23.74	$ 46.79	$ 1.40	3.08%
75		$ 10.04	$ 17.42	$ 27.45	$ 35.61	$ 63.06	$ 10.04	$ 19.52	$ 29.55	$ 35.61	$ 65.16	$ 2.10	3.33%
100		$ 10.04	$ 23.22	$ 33.26	$ 47.48	$ 80.74	$ 10.04	$ 26.02	$ 36.06	$ 47.48	$ 83.54	$ 2.80	3.47%
108		$ 10.04	$ 25.08	$ 35.12	$ 51.28	$ 86.39	$ 10.04	$ 28.10	$ 38.14	$ 51.28	$ 89.42	$ 3.02	3.50%
150		$ 10.04	$ 34.83	$ 44.87	$ 71.22	$ 116.08	$ 10.04	$ 39.03	$ 49.07	$ 71.22	$ 120.28	$ 4.20	3.62%
200		$ 10.04	$ 46.44	$ 56.48	$ 94.96	$ 151.43	$ 10.04	$ 52.04	$ 62.08	$ 94.96	$ 157.03	$ 5.60	3.70%
300		$ 10.04	$ 69.66	$ 79.70	$ 142.43	$ 222.13	$ 10.04	$ 78.06	$ 88.10	$ 142.43	$ 230.53	$ 8.40	3.78%
Rg-1: Residential Firm Sales Service During Winter Months													
5		$ 10.04	$ 1.16	$ 11.20	$ 2.97	$ 14.17	$ 10.04	$ 1.30	$ 11.34	$ 2.97	$ 14.31	$ 0.14	0.99%
15		$ 10.04	$ 3.48	$ 13.52	$ 8.91	$ 22.43	$ 10.04	$ 3.90	$ 13.94	$ 8.91	$ 22.85	$ 0.42	1.87%
23		$ 10.04	$ 5.34	$ 15.38	$ 13.67	$ 29.04	$ 10.04	$ 5.98	$ 16.02	$ 13.67	$ 29.69	$ 0.64	2.22%
35		$ 10.04	$ 8.13	$ 18.16	$ 20.80	$ 38.96	$ 10.04	$ 9.11	$ 19.14	$ 20.80	$ 39.94	$ 0.98	2.52%
50		$ 10.04	$ 11.61	$ 21.65	$ 29.71	$ 51.36	$ 10.04	$ 13.01	$ 23.05	$ 29.71	$ 52.76	$ 1.40	2.73%
75		$ 10.04	$ 17.42	$ 27.45	$ 44.56	$ 72.02	$ 10.04	$ 19.52	$ 29.55	$ 44.56	$ 74.12	$ 2.10	2.92%
100		$ 10.04	$ 23.22	$ 33.26	$ 59.42	$ 92.68	$ 10.04	$ 26.02	$ 36.06	$ 59.42	$ 95.48	$ 2.80	3.02%
108	avg.	$ 10.04	$ 25.08	$ 35.12	$ 64.17	$ 99.29	$ 10.04	$ 28.10	$ 38.14	$ 64.17	$ 102.31	$ 3.02	3.05%
150		$ 10.04	$ 34.83	$ 44.87	$ 89.13	$ 134.00	$ 10.04	$ 39.03	$ 49.07	$ 89.13	$ 138.20	$ 4.20	3.13%
200		$ 10.04	$ 46.44	$ 56.48	$ 118.84	$ 175.32	$ 10.04	$ 52.04	$ 62.08	$ 118.84	$ 180.92	$ 5.60	3.19%
300		$ 10.04	$ 69.66	$ 79.70	$ 178.26	$ 257.96	$ 10.04	$ 78.06	$ 88.10	$ 178.26	$ 266.36	$ 8.40	3.26%
							$ -	0					
Avg. Annual Residential Billing							$ -	0					
786		$ 120.45	$ 182.51	$ 302.96	$ 450.56	$ 753.52	$ 120.45	$ 204.52	$ 324.97	$ 450.56	$ 775.52	$ 22.01	2.92%

Purchased Gas Adjustment/ Gas Cost Recovery Mechanism (continued)

5. SURCHARGE COSTS: The surcharge costs, which include FERC approved surcharges for gas purchases or transportation by pipelines or other suppliers shall be computed by dividing the company's total costs associated with surcharges for the period by the total forecasted weather normal sales therms for the program year then multiplied by the total weather normal natural gas therm usage forecasted for sales customers participating in the Fixed Gas Bill Program to arrive at a surcharge cost associated with the Fixed Gas Bill Program. Surcharge costs to be applied to the Fixed Gas Bill Program shall be accounted for separately from natural gas costs in the company's natural gas portfolio.

   Program rates are on a per customer basis and shall not change for the duration of the program contract period. Rates will be recalculated at the time of renewal of contracts of customers participating in the Fixed Gas Bill Program.
   Administrative Charge Percentage: The program administrative charge shall be a premium charged to the customer in accordance with 7e of tariff schedule X-615.

6. RECONCILIATION OF GAS COSTS: Gas Costs: Monthly, the cost of gas and recoveries shall be booked separately from the Purchased Gas Adjustment/ Gas Cost Recovery Mechanism as found on Schedule X-220. Customers participating in the Fixed Gas Bill Program will not be subject to natural gas cost reconciliation adjustments.

   Customers not participating in the Fixed Gas Bill Program will not be affected by any natural gas reconciliation amount from this program.

~~7. REQUIRED APPROVALS AND REPORTS: The company shall file with the PSCW such reports as may be required by the Commission to monitor the operation of the Fixed Gas Bill Program.~~

7~~8~~. REFUND PROVISION Customers participating in the Fixed Gas Bill Program shall not be eligible for wholesale refunds.

General Conditions of Delivery
(continued)

7. Rates applied to customers weather normalized consumption data to determine the customer's monthly fixed bill amount shall include:
    a. all the fixed and variable marginal rates applicable for their corresponding sales rate class schedule and tariff schedule X-100 per firm sales service;
    b. plus a factor for gas costs as provided in the most recent gas supply plan or purchased gas adjustment affecting peak demand, annual demand and FERC authorized surcharges;
    c. plus a charge for commodity natural gas costs that shall be fixed by the company prior to the start of the program year;
    d. less any efficiency reward;
    e. plus an administrative charge of 7% of the customer's total charges before sales tax.
    f. Total costs for one year's participation in the Fixed Gas Bill Program arrived at by applying rates to weather normalized consumption plus all appropriate fixed charges shall be divided by twelve to arrive at the customer's monthly fixed bill amount before sales tax.

8. Customers participating in the Fixed Gas Bill Program shall not be eligible for pipeline refunds, and refunds or credits due to the Company's Gas Cost Recovery Mechanism. However, participating customers may be eligible to receive a credit or refund as determined by the Company ~~and approved by the PSCW~~ for any profitability refund for the November to October program year.

9. Early termination/cancellation of customers from the Fixed Gas Bill Program shall be subject to the rate switching provisions as found in paragraph 2 on tariff schedule X-605.

10. The company will use reasonable diligence to provide an uninterrupted supply of gas, but it shall not be liable for interruptions, deficiencies, or imperfections of service. The company may temporarily suspend the delivery of service when necessary for the purpose of making repairs, changes, and improvements upon any part of its system without compensation to the customer.

Appendix F

Wisconsin Electric Power Company
Docket 5-UR-107 2015 Fuel Cost Plan
Electric Fuel Costs per Wis. Admin. Code § PSC 116.02

	Monitored Fuel Costs	Net kWh Produced	Fuel Cost per Net kWh Produced	Cumulative Cost per kWh
January	$ 65,303,455	2,299,928,000	$ 0.02839	$ 0.02839
February	62,787,163	2,074,917,000	0.03026	0.02928
March	59,498,862	2,135,368,000	0.02786	0.02881
April	54,634,609	1,998,214,000	0.02734	0.02847
May	66,819,172	2,081,337,000	0.03210	0.02918
June	74,212,957	2,261,588,000	0.03281	0.02982
July	94,226,979	2,540,296,000	0.03709	0.03102
August	85,461,966	2,481,475,000	0.03444	0.03150
September	71,927,883	2,138,424,000	0.03364	0.03173
October	58,620,688	2,114,753,000	0.02772	0.03134
November	55,897,765	2,007,570,000	0.02784	0.03105
December	66,519,528	2,205,818,000	0.03016	0.03098
Total	$ 815,911,026	26,339,688,000	$ 0.03098	$ 0.03098

PUBLIC SERVICE COMMISSION OF WISCONSIN

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	5-UR-107

DISSENT OF COMMISISONER ERIC CALLISTO

I dissent from the Final Decision. While I concur with the Commission on individual portions of the Final Decision, the issues on which we disagree are too great and too impactful for me to ultimately concur in the ordered rate adjustment. The Commission's Final Decision takes dollars *twice* recovered from customers for the same purpose and lets WEPCO keep them. It imposes a 75 percent fixed charge increase on residential and small commercial customers. And it orders a new, and insufficiently supported, fee on distributed generation customers. In doing all this, the Commission gives WEPCO exactly what it asked for, despite the voluminous testimony in opposition from Commission technical staff, and in the face of heated disagreement from customers and numerous other interested stakeholders. For these reasons, I am unable to join in the ultimate conclusion approving a change in WEPCO's rates, and I write separately to provide more detail on my major areas of disagreement with the majority.

Treatment of 2014 SSR Revenues

The majority concludes that WEPCO should be allowed to retain the PIPP SSR revenues it received in 2014 – some $44 million. To get to this conclusion, my colleagues misconstrue one of our earlier decisions, and sidestep a foundational obligation of this Commission to balance consumer and utility interests. These are rightfully ratepayer dollars, and the majority conclusion is nothing less than a gift to WEPCO shareholders.

To be sure, the Escanaba order is not a model of clarity. But it is clear that when we made that decision, we had before us the argument of CUB and WIEG that double recovery was at the heart of their concerns.[1] The only substantive order point from the Escanaba order supports an interpretation that costs and revenues are to be considered: "Net SSR costs shall be deferred through December 31, 2015, for the Wisconsin Utilities."[2] Commission staff believes that equity requires that the order, or our subsequent clarification thereof, should treat costs and revenues equally.[3] And as argued by Commission staff witness Mr. O'Brien, deferral makes sense with the 2014 SSR revenues because the amounts are significant and shifting, given the changes resulting from continuing refinement by FERC of the allocation of the costs and the possibility for the SSR agreement to change on relatively short notice.[4] We should interpret that order rationally, and apply it to both sides of the SSR coin.[5] Or we should clarify it to make clear that the deferral applies to both SSR costs and revenues. To do anything else, particularly

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[1] *See* Surrebuttal-WIEG/CUB-Maini-8r to 9r.
[2] *See Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates,* docket 4220-UR-118, Final Decision at page 3 (emphasis added) (PSC REF#: 184209) (April 30, 2013) (Escanaba order).
[3] *See* Direct-PSC-O'Brien-9.
[4] *See* Direct-PSC-O'Brien-9; Surrebuttal-PSC-O'Brien-2.
[5] The majority argues, essentially, that the Commission was only aware of one side of the SSR coin when it issued the Escanaba order on April 30, 2013: "No Wisconsin utility was in line to receive any SSR revenue under the Escanaba SSR agreement." *See* Final Decision in this docket, at page 32. While perhaps technically accurate, that statement ignores the fact that this Commission has been on notice for a long time – and prior to April 30, 2013 – that PIPP is crucial to reliability in the Upper Peninsula. WEPCO itself told the Commission as much in the very application to transfer a portion of PIPP to Wolverine Power Supply Cooperative. It made its application for that transfer to this Commission on February 14, 2013, and in describing its MATS compliance options it stated "Compliance with the more stringent environmental standards cannot be accomplished by simply retiring the PIPP units. MISO confirmed that retirement of the PIPP units is not a reasonable alternative in a letter to Wisconsin Electric dated January 19, 2012: 'After being reviewed for the power system reliability impacts as provided for under Section 28.2.7 of the Midwest ISO's Open Access Transmission, Energy & Operating Reserves Tariff ("Tariff") the retirement of the units prior to installation of transmission upgrades to the greater Marquette, MI area would result in violation of applicable reliability standards, creating unacceptable reliability issues.'" (PSC REF#: 180875 at 5-6) (emphasis in original). The SSR elephant in the room has always been PIPP, as reflected by the large dollars at issue in this case and in the Commission's litigation at FERC on PIPP SSR cost allocation.

given the magnitude of the dollars at stake, is a disservice to customers and a windfall to WEPCO, which by all accounts is in sound financial shape.[6]

And other than the contorted reading of the Escanaba order, the majority fails to address the 2014 ratemaking treatment already afforded WEPCO and the purpose of SSR payments. As noted by CUB and WIEG witness Ms. Maini, Wisconsin base rates in 2014 already include the costs to operate PIPP.[7] The test year presumed the operation of PIPP in 2014, and thus its costs–at least $48.8 million[8]–were rolled into Wisconsin rates. The majority makes no mention of this, and concludes that "the Commission must treat that [SSR] revenue just as it would treat any other unexpected cost or revenue incurred or received by a utility between rate cases."[9] Whatever our obligation is to treat unexpected revenue between cases, it cannot be that we are to slavishly apply that principle while ignoring that its application means WEPCO double recovers.

WEPCO certainly did lose load in Michigan when the mines switched providers. This is one of the major risks for any utility, and it is unprecedented that we mitigate sales risk after the fact by attempting to make the utility whole for the loss. These extra revenues result from the PIPP SSR agreements between MISO and WEPCO, and there is no basis in the agreements for offsetting the lost load revenues – these are temporary payments made to a critical generation unit to ensure grid reliability.[10] They should not be used to cure WEPCO's misfortunes in the

[6] *See* Surrebuttal-WIEG/CUB-Maini-11r.
[7] *See* Surrebuttal-WIEG/CUB-Maini-8r.
[8] *See* Surrebuttal-WIEG/CUB-Maini-8r; Joint Initial Brief of CUB & WIEG Regarding SSR Issues, at 7-8.
[9] *See* Final Decision in this docket, at 32.
[10] *See* Surrebuttal-WIEG/CUB-Maini-7r. The majority understands the purpose of SSR payments, as it noted in the Escanaba order: "SSR costs result when a generation owner wishes to retire a generating unit that is losing money due to low locational marginal prices (LMPs) for its unit, <u>but MISO needs the unit for system reliability</u>. MISO would require the generating unit to remain in service, <u>but the Generator Owner would be compensated for keeping the unit in service.</u>" Escanaba order at 1-2 (emphasis added).

Upper Peninsula, particularly where WEPCO's Wisconsin customers are already paying their fair share through 2014 rates.

While we disagree with the Michigan Public Service Commission (MPSC) on almost everything concerning PIPP costs, the MPSC got it right when WEPCO tried this same approach over there.[11] The MPSC largely rejected the WEPCO request to defer the loss of revenue.[12] WEPCO then took its Michigan losses back across the border and this Commission is giving WEPCO what it could not get in the jurisdiction that is creating the issue – recovery for lost sales, leading to double recovery from Wisconsin ratepayers. And it did so after sitting on its hands in Wisconsin, waiting until the rate case to stake its claim. It could have – and should have–had this addressed earlier in the year.

As CUB and WIEG note in their joint reply brief, the Wisconsin Supreme Court has found that "[t]he primary purpose of the public utility laws in this state is the protection of the consuming public."[13] The majority's treatment of this issue fails to uphold that purpose.

Return on Common Equity

I dissent from the 10.20 percent return on equity (ROE) set by the Commission for WEPCO, and as negotiated by the Settlement Parties. 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

[11] It is ironic, of course, that we are giving WEPCO shareholders these dollars at Wisconsin ratepayer expense when we are otherwise fighting – and winning – at FERC on the allocation of PIPP SSR costs to costs causers, who reside primarily in Michigan. *Midcontinent Independent System Operator*, 148 F.E.R.C. ¶ 61,071 (2014) (petitions for rehearing pending).
[12] *See* Surrebuttal-WIEG/CUB-Maini-11r to 12r and Ex.-WIEG/CUB-Maini-2.
[13] *Wisconsin's Environmental Decade v. Pub. Serv. Comm'n*, 81 Wis. 2d 344, 351, 260 N.W.2d 712 (1978).

of 10.00 percent 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 We Energies' 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. We also know that increasing fixed customer charges reduces a utility's financial risk. That there is a direct relationship between increasing fixed charges and financial risk reduction is not in question. I note the testimony of MMSD witness, and former Chairman of this Commission, Dr. Cicchetti "urg[ing] the Commission to consider an appropriate reduction in the authorized return for WEPCO, given the substantially reduced risks in the new tariff design."[14] I would have preferred that the Commission's ROE decision take that into account.

Fixed Facilities Charges & Generic Investigation on Rate Design

I disagree with the Commission's decision to increase fixed facilities charges on WEPCO's residential and small commercial electric customers. I disagree for many of the same reasons that I opposed the fixed charge increases for Wisconsin Public Service Corporation (WPSC), in docket 6690-UR-123.[15] It is poor regulatory policy. It is unfair. And it is being accomplished piecemeal, in separate rate case proceedings, over the sound and well-reasoned

[14] *See* Direct-MMSD-Cicchetti-14.
[15] *Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates,* docket 6690-UR-123, Final Decision, at 2 to 13 of Concurrence and Dissent of Commissioner Eric Callisto. (PSC REF#: 226374) (December 18, 2014).

objections of Commission technical staff, and in the face of overwhelming public and stakeholder opposition. 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 facilities charge increases are steep. For electric residential and small commercial customers, fixed charges will immediately go up 75 percent.[16] 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.

The Commission invokes the notion of "fairness" to justify increasing the fixed charge by 75 percent.[17] The rationale 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. Substantially increasing the fixed portion of a customer's bill will "reduce intra-class subsidies" and "provide more appropriate prize signals," according to the Final Decision.[18]

I have acknowledged the theoretical appeal underlying the fixed facilities charge proposal.[19] But setting and designing utility rates is about more than theory. It is about more than cost of service engineering. And it should involve much more than simply endorsing what a utility puts in its application.

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[16] The dollar increase is from $9.13 to $16.00. Final Decision in this docket, at page 57.
[17] Final Decision in this docket, at 64.
[18] Final Decision in this docket, at 69.
[19] *Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates*, docket 6690-UR-123, Final Decision, at 3 to 4 of Concurrence and Dissent of Commissioner Eric Callisto. (PSC REF#: 226374) (December 18, 2014).

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

> In this proceeding, WEPCO 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.[20]

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 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 WEPCO's proposed fixed facilities charge increases. Three Commission staff witnesses, an Assistant Administrator in the Gas and Energy Division, a Senior Rate Engineer, and an Energy Policy Analyst, all offered testimony on the fixed facilities charge proposal. Their recommendations were not adopted by the Commission, and their input was ignored. Commission staff witness Mr. Albrecht stated the following:

> I limited the single-phase facilities charge increase in my proposed alternative rate design to 20 percent. This balances the company's desire to have higher facilities

[20] Final Decision in this docket, at 58.

> charges that are closer to the COSS without the significant bill impacts for some customers.[21]

Mr. Albrecht went on to explain his reasoning:

> First, there were recent Commission decisions where 40 percent utility-proposed facilities/customer charge increases were limited to 20 percent. This occurred in the most recent WEPCO rate case in docket 05-UR-106 and in docket 3270-UR-119 for Madison Gas and Electric Company last year. Secondly, I agree with Commission staff witness Corey Singletary that the appropriate upper limit for the appropriate costs that should be included in the facilities charges is less than the $16 WEPCO proposed for its single-phase customers. The company has not demonstrated an urgent need to significantly increase the facilities charges all at once. WEPCO's proposal far exceeds what the Commission accepted as reasonable in the recent rate cases referenced above. If the facilities charges are changed it should be done gradually.[22]

Mr. Albrecht's proposed electric rate design included customer charge increases of 20 percent for residential and small commercial customers (from $9.13 to $10.95). The Commission instead is ordering an increase of 75 percent (from $9.13 to $16.00).

Commission staff witness Mr. Singletary also submitted testimony regarding the fixed facilities charge issue. Mr. Singletary specifically addressed the supposed necessity of increasing fixed charges in furtherance of 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, WEPCO 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.[23]

[21] Direct-PSC-Albrecht-6.
[22] Direct-PSC-Albrecht-6 to 7.
[23] Direct-PSC-Singletary-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 (Ex.-WEPCO/WG-Rogers-12, Schedule 32) so as to remove primary-voltage distribution costs that are classified as customer-related 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 WEPCO's system.[24]

Mr. Singletary's cost analysis suggested fixed cost levels of no more than $11.60 per customer, for the small customer classes.[25] The Commission is ordering a $16.00 fixed charge for residential customers and small commercial customers.

Mr. Singletary further elaborated on the impact that increasing fixed facilities charges will have on price signals. He explained:

> Utility witnesses Rogers and O'Sheasy have both discussed the importance of proper price signals so as to encourage efficient market behavior. However, I believe that the utility's view of price signals to be one-sided and does not consider the fact that recovery of production costs through 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

[24] Direct-PSC-Singletary-17.
[25] Direct-PSC-Singletary-18.

> 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.[26]

In contrast, the Commission's Final Decision concludes that increasing the fixed facilities charge for electric customers by 75 percent will "encourage[] efficient utility scale planning."[27] However, nowhere in the Final Decision is it explained how muting customer price signals will accomplish such an objective.

And regarding how the fixed facilities charge increase would specifically affect energy efficiency and conservation, Commission staff witness Ms. Stemrich stated:

> Collecting a higher portion of those costs from fixed charges, and its resultant reduction in volumetric rates, reduces the benefits a customer receives by reducing the cost savings achieved from implementing an energy efficiency measure . . . While a small increase in fixed charges is not likely to result in many energy efficiency measures no longer being cost-effective for the customer to implement, larger increases will . . . WEPCO's proposal creates a level of uncertainty regarding future benefits from any actions taken by customers. Customers may be reluctant to implement energy efficiency measures even if economically beneficial under WEPCO's proposed 2015 rates because they have no certainty that the company will not continue to pursue increased fixed charges in the future.[28]

Ms. Stemrich ultimately concluded that increasing the fixed facilities charge to $16.00 "will make it more difficult to achieve cost-effective energy efficiency potential," and that "[w]hile

[26] Direct-PSC-Singletary-32. Mr. Singletary also testified how appropriate rate design should take into account the long term variability of energy supply costs: "To be sure, in the short term utility production plant costs are largely fixed. However, in the mid to long term, all energy supply is variable. Even if we are willing to accept the assumption that the distribution system is immutable regardless of customer usage levels or usage patterns, production must be considered variable in the long term, particularly if we are to realistically consider a utility future where decreased sales are expected . . . Rate design . . . is principally concerned with influencing behavior for the future." Direct-PSC-Singletary-31.

[27] Final Decision in this docket, at 62.

[28] Surrebuttal-PSC-Stemrich-3.

recovering more utility costs through fixed charges may assist in meeting other policy goals, it is detrimental to the achievement of cost-effective energy efficiency."[29]

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 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,"[30] 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 $11.60 per customer;
- A recognition that steep fixed customer charge increases unfairly impact low usage customers;

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[29] Surrebuttal-PSC-Stemrich-4. Mr. Albrecht also testified regarding impacts to energy conservation: "Generally lower facilities charge and higher energy charges for the small usage classes could encourage more energy conservation, since the customers would see more savings from reductions in kilowatt-hour (kWh) usage." Direct-PSC-Albrecht-6. 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.

[30] Final Decision in this docket, at 58.

- 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 total and complete endorsement of WEPCO's push to increase its fixed facilities charges. And it is a reached in the face of plain and unequivocal opposition from Commission technical staff.

The Commission's Final Decision on fixed charges has other problems. It "finds that it is not necessary at this time to specify what specific costs are appropriate to consider when setting fixed charge rates,"[31] yet concludes "that the fixed customer charges should be increased to more closely reflect WEPCO's fixed costs to provide basic service to a customer."[32] It ignores record evidence showing that it is more likely that low income residents in WEPCO's service territory are low usage customers, and thus those customers will be disproportionately

[31] Final Decision in this docket, at 13.
[32] Final Decision in this docket, at 69.

harmed by the fixed charge increase.[33] 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 incorrectly, and without support, suggests that WEPCO's current rate design "results in under-recovery."[34] 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 WEPCO'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."[35] 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 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. WEPCO's own witnesses concede that 59 percent of residential

[33] *See, e.g., Public Comment of John Howat, National Consumer Law Center on Behalf of Wisconsin Community Action Program Association,* (PSC REF#: 221477) (October 6, 2014); Direct-WEPCO/WG-O'Sheasy-8r ("Some stakeholders will argue (with some support) that low-*use* customers are more likely to be low-*income* customers, so that the change in rate design harms the poor while benefiting those who are better off.") (emphasis in original).

[34] Final Decision in this docket, at 67-68. There is no suggestion in this proceeding that WEPCO is under-recovering its revenues, or that it will in the coming years.

[35] Final Decision in this docket, at 60.

customers will have a utility bill increase solely because of the fixed charge increase.[36] And for 12 percent of their customers, the bill increase will be more than 10 percent.[37] We also know that 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 WEPCO 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.

[36] *See* Direct-WEPCO/WG-Rogers-35-36.
[37] *See id.*

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.

Distributed Generation Tariff Changes

I disagree with the Commission's changes to WEPCO's DG tariffs, specifically the imposition of a new capacity demand charge, and the switch from annual to monthly netting for net metering customers. These changes will further erode the economics of distributed generation for WEPCO customers and for reasons that are neither sufficiently explained nor supported by the evidentiary record in this proceeding.

I disagree with the capacity demand charge adopted by the Commission because it is largely arbitrary. While the stated purpose for the charge is "to recover standby generation and distribution costs that are not recovered by the facilities charge of the underlying rate,"[38] the Commission is unable to point to any record evidence demonstrating the amount or scope of additional distribution costs that are specific to distributed generation customers, and which would justify differential fixed, demand charge treatment. Yet the Commission concludes that "it is reasonable to establish the demand charge based on the name-plate capacity of the generating equipment,"[39] even though there is no showing that name-plate capacity of the various forms of distributed generation accurately reflects what either the actual output of the distributed generation facility will be or the customer's actual demand on the utility system. As Commission staff witness Mr. Singletary points out, the proposed demand charge is

[38] Applicants' Initial Post-Hearing Brief, at 19.
[39] Final Decision in this docket, at page 84.

"speculative" and "theoretical," further stating that he does "not believe that the Company has provided sufficient evidence to support these new charges."[40]

And while the Commission acknowledges that "there are some questions regarding how closely the name-plate capacity reflects actual demand," its proposed remedy, installation of additional metering and a potential true-up process two years from now, is poorly explained. The new metering apparently will compare the actual output of the customer's generation facility with its name-plate capacity, and "[i]f the customer's actual monthly maximum generation capacity is lower than the rated nameplate capacity, a credit shall be issued to the customer reflecting the difference for those billing periods."[41] But that sort of comparison will not necessarily capture what a customer's actual demand is on the system, particularly where the distributed generation facility's actual capacity exceeds a customer's demand needs. I also note that fundamentally WEPCO "has not provided evidence that the utility in fact does or would incur additional generation capacity charges in order to meet the supply needs of customers with DG systems smaller than 300 kW in size."[42] It is not supportable to require customers that are new to the DG tariffs to sign up for an extra demand charge based on name-plate capacity that the Commission itself acknowledges is problematic, based on the *possibility* that in the future they might receive some sort of credit once new metering becomes available.

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[40] Direct-PSC-Singletary-27.
[41] *See* Final Decision in this docket, at pages 84-85.
[42] Direct-PSC-Singletary-30.

The whole framework is not sufficiently developed, has a last-minute, thrown-together feel, and is ultimately arbitrary.[43] The Commission would be well advised to just start over, do an actual cost analysis for DG customers, and develop tariffs with a proper evidentiary foundation and which do not unjustly harm certain customers simply because they choose to install distributed generation systems. A proper analysis could be accomplished in conjunction with the generic investigation that I am recommending in this proceeding and in other rate proceedings this year.

I similarly disagree with the Commission's decision to impose monthly netting for net metering customers. The Commission just ordered annual netting for these customers in WEPCO's most recent rate proceeding.[44] Why we must reverse course now, at the expense of net metering customers, is not sufficiently explained.

I respectfully dissent.

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[43] I also note the problems associated with WEPCO's grandfathering proposal for existing DG customers. While I join in supporting a grandfathering mechanism, I am troubled by the fact that it was not raised in this proceeding until the briefing stage, that there was no evidence offered on it, and that parties were not afforded an opportunity to submit supporting or countervailing evidence.

[44] *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 05-UR-106, Final Decision, Order Point 32, (PSC REF#: 178105) (December 21, 2012).