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-106

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 increase electric and steam rates on January 1, 2013, and January 1, 2014, and to decrease natural gas rates on January 1, 2013.

Final overall rate changes in 2013 are authorized consisting of a $114,821,000 annual rate increase for WEPCO Wisconsin retail electric operations, a 4.15 percent increase; an $8,052,000 annual rate decrease for WEPCO natural gas operations (WE-GO), a 1.92 percent decrease; a $1,256,000 annual rate increase for WEPCO's Valley Steam (VA Steam)[1] operations, a 6.00 percent increase; a $1,040,000 annual rate increase for WEPCO's Milwaukee County steam (MC Steam)[2] operations, a 7.00 percent increase; and a $34,281,000 annual rate decrease for WG, a 5.49 percent decrease, for the test year ending December 31, 2013, based on a 10.40 percent return on common equity for WEPCO and a 10.50 percent return on common equity for WG.

Additional overall rate changes in 2014 are authorized consisting of a $73,442,000 annual rate increase for WEPCO Wisconsin retail electric operations, a 2.55 percent increase; a $1,332,000 annual rate increase for WEPCO's VA Steam, a 6.00 percent increase; and a

[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.

$954,000 annual rate increase for WEPCO's MC Steam operations, a 6.00 percent increase; for the test year ending December 31, 2014, based on continuation of a 10.40 percent return on common equity for WEPCO.

Introduction

In this Final Decision, any reference to WG and the four utility operations under WEPCO, collectively, will use the general name "We Energies" and any reference to the holding company, Wisconsin Energy Corporation, will use the acronym "WEC."

On March 23, 2012, We Energies requested Wisconsin jurisdictional revenue increases of $151.3 million (5.5 percent) in 2013 and $103.8 million (3.6 percent) in 2014 for its electric operations; a $1.2 million (0.2 percent) revenue decrease for its natural gas operations (WE-GO) in 2013; $1.3 million (6.0 percent) revenue increases in both 2013 and 2014 for its VA Steam; and $1.0 million (7.0 percent) revenue increases in both 2013 and 2014 for its MC Steam operations. WG requested a $15.9 million (2.3 percent) decrease for natural gas operations in 2013. WEPCO's requested electric increase includes its proposal to include the tax benefits arising from its Rothschild biomass construction project to customers over the two-year period 2013 and 2014.

On June 15, 2012, WEPCO updated its 2013 electric utility fuel costs resulting in a revised electric rate increase request of $138.1 million (5.0 percent) in 2013 and $104.1 million (3.6 percent) in 2014.

On May 21, 2012, a prehearing conference was held to determine the issues to be addressed in this docket and to establish a schedule for the hearing. Hearings were held on September 26, 2012, in Madison, to receive technical information and public comments into the record. Additional hearings were held on October 1, 2012, in Milwaukee and Brookfield to receive public comments into the record.

The Commission considered this matter at its open meeting of November 28, 2012. 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 $2,872,469,000 for the test year ending December 31, 2013, which results in a net operating income of $247,279,000 and an annual revenue deficiency of $114,821,000.

2. Presently authorized rates for WEPCO's natural gas utility operations will produce operating revenues of $421,240,000 for the test year ending December 31, 2013, which results in a net operating income of $38,870,000 and an annual revenue excess of $8,052,000.

3. Presently authorized rates for WEPCO's VA Steam utility operations will produce operating revenues of $20,888,000 for the test year ending December 31, 2013, which results in a net operating income of $1,130,000 and an annual revenue deficiency of $2,588,000 to be recovered in rates during the 2013-2014 biennium.

4. Presently authorized rates for WEPCO's MC Steam utility operations will produce operating revenues of $14,858,000 for the test year ending December 31, 2013, which results in a net operating income of $844,000 and an annual revenue deficiency of $1,994,000 to be recovered in rates during the 2013-2014 biennium.

5. Presently authorized electric and steam rates of WEPCO are unreasonable because they produce inadequate electric and steam revenues.

6. Presently authorized natural gas rates of WEPCO are unreasonable because they produce excess natural gas revenues.

7. Presently authorized rates for WG's natural gas utility operations will produce operating revenues of $628,793,000 for the test year ending December 31, 2013, which results in a net operating income of $80,172,000 and an annual revenue excess of $34,281,000.

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

9. For the WEPCO Wisconsin retail electric utility, the estimated rate of return on average net investment rate base of $3,928,415,000 at current rates subject to the Commission's jurisdiction for the test year is 6.29 percent, which is inadequate.

10. For WE-GO, the estimated rate of return on average net investment rate base of $370,965,000 at current rates subject to the Commission's jurisdiction for the test year is 10.48 percent, which is excessive.

11. For the WEPCO VA Steam utility operations, the estimated rate of return on average net investment rate base of $29,201,000 at current rates subject to the Commission's jurisdiction for the test year is 3.87 percent, which is inadequate.

12. For the WEPCO MC Steam utility operations, the estimated rate of return on average net investment rate base of $22,228,000 at current rates subject to the Commission's jurisdiction for the test year is 3.80 percent, which is inadequate.

13. For the WG natural gas utility, the estimated rate of return on average net investment rate base of $664,799,000 at current rates subject to the Commission's jurisdiction for the test year is 12.06 percent, which is excessive.

14. A reasonable increase in operating revenue for the test year to produce a 9.15 percent return on WEPCO's average net investment rate base for Wisconsin retail electric operations is $114,821,000.

15. A reasonable decrease in operating revenue for the test year to produce a 9.15 percent return on WEPCO's average net investment rate base for natural gas operations is $8,052,000.

16. A reasonable increase in operating revenue for the test year to produce a 9.17 percent return on WEPCO's average net investment rate base for VA Steam utility operations is $1,256,000 in 2013 and $1,332,000 in 2014.

17. A reasonable increase in operating revenue for the test year to produce a 9.18 percent return on WEPCO's average net investment rate base for MC Steam utility operations is $1,040,000 in 2013 and $954,000 in 2014.

18. A reasonable decrease in operating revenue for the test year to produce an 8.96 percent return on WG's average net investment rate base for natural gas operations is $34,281,000.

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. A 2013 total company test-year fuel cost of $1,098.25 million is reasonable.

21. A 2013 total company test-year fuel rules monitoring level of fuel costs of $980.53 million, or $33.34 per megawatt-hour (MWh), as shown in Appendix F, is reasonable.

22. It is reasonable to forecast the fuel cost plan-year natural gas prices, heating oil, and crude oil prices for rail transportation fuel surcharges by using the October 18, 2012, New York Mercantile Exchange futures prices.

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

24. It is reasonable to reflect the $7.8 million increase in fuel costs for American Transmission Company's (ATC) line rating reductions, offset by an assumption that Financial Transmission Rights (FTR) will provide revenues to offset 75 percent of those costs. It is not reasonable to require deferral treatment for these costs as it would be too difficult to separate such costs from the remaining fuel costs.

25. It is reasonable to include the impacts of the Special Protection Scheme (SPS) and the second Pleasant Prairie to Zion transmission line, to be offset by 75 percent for the loss of FTR revenues.

26. It is reasonable to reflect WEPCO's original estimate of $13.867 million for chemical costs.

27. It is reasonable to retain the allocations of the Valley Power Plant.

28. It is reasonable to incorporate the reduction in coal sales revenue from the mines.

29. Because the Cross-State Air Pollution Rule (CSAPR) was vacated on August 21, 2012, it is reasonable to remove all associated costs and revenues from the revenue requirement.

30. It is reasonable, in future proceedings, to require WEPCO to model its portion of the ERGS units as economic in the MISO energy market during the non-summer months of the test year.

31. The definition of *force majeure*, for purposes of determining the Elm Road Generating Station (ERGS) Approved Amount, is the facility lease definition.

32. The $72.0 million in ERGS cost over-run incurred to settle the $517 million claim brought by Bechtel Corporation (Bechtel) was prudently incurred.

33. The $12,094,893 in ERGS cost over-run associated with the legal defense of the Bechtel claim was prudently incurred.

34. The $1,063,252 in ERGS cost over-run associated with the internal legal cost component of WEPCO's Wisconsin Pollutant Discharge Elimination System (WPDES) litigation defense, Certificate of Public Convenience and Necessity (CPCN) litigation defense, and defense of the Bechtel claim is not a double recovery of previously authorized labor expenses.

35. The $1.0 million in ERGS cost over-run incurred to address unforeseen sub-surface conditions was prudently incurred.

36. Deferring recovery of the $24.3 million already incurred by WEPCO for ERGS fuel flexibility, plus any other expenditures related to fuel flexibility, including carrying costs for the $24 million, for review in a future rate case is reasonable. The carrying costs shall be calculated using the short-term cost of debt.

37. The $44,862,081 in ERGS cost over-run caused by the delay in commencing construction due to the vacation and reinstatement of the CPCN was *force majeure* and was prudently incurred.

38. The $5,828,982 in ERGS cost over-run caused by the United States (U.S.) Army Corps of Engineers' special permit conditions was not *force majeure*, but was prudently incurred.

39. The $3,567,077 in ERGS cost over-run caused by the modification to the railroad crossings in the Village of Caledonia was not *force majeure*, but was prudently incurred.

40. The annual payments under the WPDES settlement agreement will continue to be reviewed by the Commission on a rate case by rate case basis. It is not reasonable to allow recovery of the annual payment in 2013 or 2014.

41. Deferring recovery of the ERGS cost over-run associated with the legal fees incurred in defense of the WPDES lawsuit for review in a future rate case is reasonable.

42. The ERGS cost over-run of $10,000,000 caused by the Department of Labor’s Occupational Safety and Health Administration (OSHA) decision to change the administrative rule governing exposure to hexavalent chromium was *force majeure* and was prudently incurred.

43. The ERGS cost over-run of $851,000 caused by the U.S. Environmental Protection Agency’s (EPA) requirement regarding mercury emission monitoring was *force majeure* and was prudently incurred.

44. The ERGS cost over-run of $1,813,000 caused by the change in Wisconsin payroll tax law was not *force majeure*, but was prudently incurred.

45. The ERGS cost over-run associated with the severe rainstorms on July 22 and 23, 2010, was *force majeure* and was prudently incurred.

46. The ERGS cost over-run associated with the consolidation of events, such as delivery interruption due to Hurricane Ike, a volcanic eruption in Iceland, a Waste Management strike, and Bowl and Dock fire protection issues, totals $438,515. The Bowl and Dock fire

protection issues were not *force majeure*, leaving only $137,980 as *force majeure*. The entire amount of $438,515 was prudently incurred.

47. The cost issue associated with the low-pressure turbine corrosion is not yet resolved. This cost should be escrowed and be part of a future rate proceeding subject to a prudence determination at that time.

48. ERGS cost items not yet settled, such as punch list and final cost review items, should be part of a future rate proceeding subject to a prudence determination at that time.

49. It is reasonable to include an average number of employee positions of 4,179 for WEPCO and 449 for WG for purposes of determining revenue requirement.

50. It is reasonable to reduce the company's filed estimate of non-labor, non-fuel electric production operations and maintenance (O&M) expense by $11.6 million on a total company basis or $9.8 million on a Wisconsin retail basis.

51. It is reasonable to reduce the company's filed estimate of non-labor, electric distribution O&M expense by $5.5 million on a total company basis or $5.2 million on a Wisconsin retail basis.

52. It is reasonable to reinstate the transmission escrow on a temporary basis and to accrue carrying costs on the deferred net-of-tax balance calculated at the authorized short-term debt rate.

53. It is reasonable to provide rate recovery of non-labor transmission expenses of $250.7 million on a Wisconsin retail basis in 2013 and 2014.

54. A reasonable estimate of non-labor transmission expenditures for 2013 and 2014 is $286,198,240 and $311,155,853 on a total company basis.

55. A reasonable estimate of escrowed uncollectible accounts expense for WEPCO's electric utility is $26,809,000, which is comprised of $25,252,000 of estimated net write-offs and $1,557,000 of amortization expense on a Wisconsin retail basis.

56. A reasonable estimate of escrowed uncollectible accounts expense for WEPCO's gas utility is $1,622,000, which is comprised of $3,909,000 of estimated net write-offs and a negative amortization expense of $2,287,000.

57. A reasonable estimate of escrowed uncollectible accounts expense for WG is $2,808,000, which is comprised of $17,764,000 of estimated net write-offs and a negative amortization expense of $14,956,000.

58. The company's filed level of uncollectible accounts expense that is not escrowed for WEPCO's electric and gas utilities and for WG is reasonable.

59. The company's filed estimates of employee medical, dental, and post-retirement benefits other than pension expense [Statement of Financial Accounting Standards (SFAS) No. 106] are reasonable.

60. It is reasonable to exclude stock-based compensation and the directors' charitable award from the filed estimate of Board of Directors' expenses for WEPCO and WG.

61. It is reasonable to direct WEPCO to reduce the balance of its Power the Future (PTF) escrow at the beginning of the test year by $618,000 to remove bonuses and incentives charged in error to the escrow, as well as reducing the return on net working capital to reflect the lower average balance of the deferred amount.

62. It is reasonable to increase WEPCO's forecast of electric gross receipts tax expense by $2.6 million on a total company basis.

63. It is reasonable to use the most recent three-year average actual costs to forecast the test-year remainder assessments for WE-GO and WG.

64. It is appropriate to disallow $90,000 of deferred litigation expenses related to the U.S. Department of Energy (DOE) settlement for partial breach of a contract to pick up spent nuclear fuel at the Point Beach Power Plant from future rates and to continue reviewing the deferred litigation expenses associated with this settlement and address this issue in the next annual fuel reconciliation.

65. It is reasonable to continue escrow accounting treatment of the Section 199 production tax deduction.

66. It is not reasonable to create a regulatory asset for one-half of the retail portion of the 2012 Lake Michigan funding amount related to the settlement agreement with Clean Wisconsin and the Sierra Club.

67. It is appropriate to eliminate the deferred balances and test-year amortizations associated with Section 199 deferred carrying costs and deferred coal legal costs.

68. It is reasonable to reduce the 2014 step-increase by $1.2 million to reflect the Wisconsin retail revenue requirement reduction for the carrying cost benefit associated with the resulting deferred tax liability in 2014.

69. It is reasonable to authorize a 2014 electric step-increase in the amount of $73,442,000. Prior to implementation of the 2014 electric rates, it is reasonable to require WEPCO to provide a summary of actual costs related to the Rothschild biomass construction project.

70. It is reasonable to apply the Wisconsin retail portion of the Federal Section 1603 renewable energy treasury cash grant (treasury grant) proceeds between 2013 and 2014 electric revenue deficiencies as bill credits such that non-fuel increases are approximately equivalent in both years.

71. It is reasonable to authorize escrow treatment for the treasury grant benefits due to the uncertainty of the exact amount and timing of benefits to electric customers.

72. It is reasonable to authorize the proposed Revised Low Income Program (RLIP) as a permanent program.

73. We Energies should work with Commission staff to ensure the RLIP maintains a positive cost-benefit ratio.

74. It is not appropriate to include load-management expenditures in the conservation escrow budget. Funding should be included in non-escrow O&M.

75. It is not appropriate to escrow Agriculture Services program expenditures. Funding should be included in non-escrow O&M.

76. 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. For WEPCO electric, $45,848,000, which consists of $33,108,000 of estimated expenditures and $12,740,000 of amortization of underspent amounts. For WE-GO, $14,772,000, which consists of $10,436,000 of estimated expenditures and $4,336,000 of amortization of underspent amounts. For WG, $14,304,000, which consists of $12,745,000 of estimated expenditures and $1,559,000 of amortization of underspent amounts.

77. It is not appropriate to include dollars in revenue requirements for the Renewable Energy Development (RED) Program.

78. 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.

79. A long-term range of 45.0 percent to 50.0 percent for WG's common equity ratio, on a financial basis, is reasonable and provides adequate financial flexibility.

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

81. An appropriate target level for WG's test-year average common equity measured on a financial basis is 47.5 percent.

82. 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 $358,160,000.

83. A reasonable financial capital structure for WEPCO for the test year consists of 51.00 percent common equity, 0.47 percent preferred stock, 39.16 percent long-term debt, 3.90 percent short-term debt, and 5.47 percent debt equivalent of off-balance sheet obligations.

84. A reasonable financial capital structure for WG for the test year consists of 47.50 percent common equity, 33.17 percent long-term debt, and 19.33 percent short-term debt.

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

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

87. 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.

88. A reasonable utility capital structure for ratemaking for WEPCO for the test year consists of 52.09 percent common equity, 0.51 percent preferred stock, 43.10 percent long-term debt, and 4.30 percent short-term debt.

89. A reasonable utility capital structure for ratemaking for WG for the test year consists of 46.75 percent common equity, 33.65 percent long-term debt, and 19.60 percent short-term debt.

90. A reasonable interest rate for WEPCO's and WG's short-term borrowing through commercial paper is 0.53 percent for the test year.

91. A reasonable interest rate for WEPCO's proposed 30-year debentures totaling $250 million forecasted for 2012 is 3.95 percent.

92. A reasonable interest rate for WEPCO's proposed 30-year debentures totaling $350 million forecasted for 2013 is 4.55 percent.

93. A reasonable average embedded cost for WEPCO's long-term debt is 5.21 percent for the test year.

94. A reasonable interest rate for WG's proposed 30-year debentures totaling $150 million forecasted for 2013 is 4.55 percent.

95. A reasonable average embedded cost for WG's long-term debt is 5.61 percent for the test year.

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

97. The rate of return on utility common stock equity of 10.40 percent established in WEPCO's 2010 test-year rate case, docket 5-UR-104, remains in place as it was not an issue addressed in this proceeding.

98. The rate of return on utility common stock equity of 10.50 percent established in WG's 2010 test-year rate case, docket 5-UR-104, remains in place as it was not an issue addressed in this proceeding.

99. A reasonable weighted average composite cost of capital is 7.71 percent for WEPCO.

100. A reasonable weighted average composite cost of capital is 6.90 percent for WG.

101. 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.

102. 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.

103. It is reasonable to transfer existing customers between WEPCO's CGS2, CGS6, and CGS7 net metering tariffs to reorganize customers based on metering and generation type.

104. It is reasonable to close WEPCO's CGS3 and CGS6 tariffs to new customers.

105. It is not reasonable to close the CGS6 tariff retroactively.

106. It is reasonable for CGS8 customers to be able to net their generation against their consumption on an annual basis through a monthly carry-forward approach.

107. It is reasonable that CGS8 customers be paid for annual net surplus generation at an avoided cost rate that reflects average Midwest Independent Transmission System Operator, Inc. (MISO), locational marginal pricing (LMP) plus the utility's avoided cost of transmission.

108. It is reasonable that CGS8 customers are limited to 20 kilowatts (kW) of aggregate capacity per location and may, at most, size their generating equipment to match the their load requirements at the same location.

109. It is reasonable to grant WEPCO a waiver of Wis. Admin. Code § PSC 113.0406(5) ("Budget Billing") to net metering customers on tariffs CGS 2, 4, 6, 7, and 8.

110. It is reasonable for WEPCO to correct conflicting exclusionary language in WEPCO's fuel cost adjustment sheet and issue credits, including interest, to those Customer Generating Systems (CGS) customers that were not credited fuel cost adjustments, starting with bills from June 2006.

111. 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.

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

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 WEC, 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

Electric Fuel Costs

A reasonable test-year level of monitored fuel costs is $980.53 million, which reflects the cost of fuel as defined by Wis. Admin. Code § PSC 116.02. The test-year monitored fuel costs divided by the test-year estimate of native energy requirements of 29,409,947 MWh results in an average net monitored fuel cost per MWh of $33.34. Appendix F shows the monthly fuel costs to be used for monitoring purposes. The total fuel costs are based on various indices for natural gas, heating oil, and crude oil prices as of October 18, 2012. 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).

Transmission Operating Issues

WEPCO witness Mary Wolter proposed three transmission operating changes to her original filed 2013 fuel costs to reflect an $11.4 million reduction for SPS, a $3.0 million reduction for the last quarter of 2013 in-service date of the Pleasant Prairie to Zion transmission line (P4 to Zion Line 2) and a $7.8 million increase for ATC's anticipated line rating reductions to meet North American Electric Reliability Council (NERC) requirements.

Commission staff witness James Wagner included these updates in his 2013 fuel cost estimate, but offset the cost increase for the ATC line rating reductions with an increase in FTR revenues by 75 percent of the estimated cost increase. Citizens Utility Board (CUB) witness Richard Hahn testified that the cost increase for the ATC line rating reduction should not be included in the 2013 fuel cost estimate. Mr. Hahn further argued that WEPCO should not be allowed to offset the approximately $14.4 million in revenues from the SPS and the Pleasant Prairie to Zion Second Line with 75 percent of lost FTR revenue, as, according to Mr. Hahn, WEPCO's proposal came in to the process too late to allow for proper review. Mr. Wagner testified that it would be appropriate to apply the 75 percent reduction to all three transmission issues.

In rebuttal testimony, Ms. Wolter proposed that the ATC line reduction should be offset by FTR revenue by 7.5 percent compared to Mr. Wagner's estimate of 75 percent, and the cost reductions for the SPS and P4 to Zion Line 2 should be offset by a 75 percent reduction to FTR revenues. Ms. Wolter also provided rebuttal testimony indicating that the P4-Zion Line 2 was mistakenly included in the fuel model for the full year, not just the last quarter of 2013 when the new line will be in service.

The Commission finds it reasonable to reflect the $7.8 million increase in fuel costs for ATC's line rating reductions, offset by an assumption that FTRs will provide revenues to offset 75 percent of those costs. The Commission is not requiring deferral treatment of these costs as Commission staff and WEPCO both indicated that it would be too difficult to separate such costs from the remaining fuel costs.

The Commission further finds it reasonable to include the impacts of the SPS and the second Pleasant Prairie to Zion transmission line, to be offset by 75 percent for the loss of FTR revenues.

Commissioner Callisto dissents.

Ms. Wolter also indicated that the PROMOD model had included the impacts of the second Pleasant Prairie to Zion line for the entire year as opposed to only the last quarter of 2013 for a decrease in fuel costs of $2.4 million. Using the 75 percent offset applied in the other transmission adjustments, the impact would be an increase of $0.6 million. The Commission finds it reasonable to reflect an increase of $0.6 million to correct the error in the PROMOD model for the second Pleasant Prairie to Zion transmission line.

Commissioner Callisto dissents.

Chemical Costs

The original filed estimate for chemical costs was $13.867 million. Ms. Wolter proposed a decrease in chemical costs of $1.175 million described as "Reflect new dispatch volume and/or pricing." In rebuttal testimony, Ms. Wolter stated that instead of a decrease in fuel costs of $1.175 million, the revised estimate is actually an increase in fuel cost of $5.4 million due to a mathematical error in the spreadsheet that missed $6.7 million of chemical costs in the revised estimate of chemical costs. Mr. Hahn and Mr. Wagner both testified the increase in fuel costs should not be included in the 2013 fuel costs because they did not have the opportunity to review the underlying reasons for such a large increase. Mr. Wagner proposed that the chemical costs be at the original estimate of $13.867 million. WEPCO argued in its initial brief that no one has disputed that this was a spreadsheet error and that no one had objected to the underlying assumptions resulting in the increase in chemical costs.

Because the reason for this large increase has not been vetted, the Commission finds it reasonable to reflect WEPCO's original estimate of $13.867 million for chemical costs.

Valley Power Plant[3]

The proper allocation of the cost to operate the Valley Power Plant between the steam and electric utility operations had been deferred to this rate proceeding from the last WEPCO rate proceeding. The Valley Power Plant was built primarily for electric generation, and the Commission has approved the cost allocation method for the allocation of costs to steam customers in docket 2-U-7131 in 1971, and reaffirmed in docket 6630-UR-109 in 1997. Since

[3] The Commission denies CUB's motion to strike a portion of the comments to the Briefing Memorandum and Decision Matrix filed on behalf of the DMS customers. The Commission finds the comments helpful to its deliberations and concludes that CUB has not been prejudiced by the filing of these comments as CUB provided a response to these comments in its motion to strike. Commissioner Callisto dissents.

that time the economic value of the plant has significantly diminished, especially since the start of the MISO energy market. Mr. Hahn testified that steam customers are not paying their fair share of the cost to generate steam used by WEPCO's steam customers. WEPCO witness Allan Mihm testified that the Valley Power Plant is still necessary for electric reliability, and the current cost allocation is still appropriate. Mr. Hahn testified that WEPCO has not supported the need for the plant for electric reliability by bidding a minimum load as must-run and not allowing MISO to determine if the plant is needed for electric reliability.

Mr. Hahn testified that the amount of energy required to create a pound of steam was actually 1,466 British thermal units (Btus), as opposed to the 850 Btus currently assumed, resulting in a subsidy from the electric ratepayers to the steam customers of approximately $5.4 million per year. Mr. Hahn recommended that this proposed change be implemented over a five-year period, with the impact of the first year being an increase of $1.054 million to steam customers.

Mr. Mihm testified that the engineering firm HDR performed a review of fuel cost allocation methods, and HDR determined the current allocation method is viewed as a reasonable approach to fuel cost allocation. Mr. Mihm testified that the cost allocation should not be changed for the following reasons: (1) Mr. Hahn did not offer evidence that the operation of the plant as a cogeneration facility has changed or that its primary purpose of providing electric reliability to the Milwaukee area has changed; (2) the current cost allocation at the Valley Power Plant has already been deemed to be reasonable twice under the current operating conditions so it is not reasonable to change it now; and (3) the rate impact on the 400 steam customers caused by Mr. Hahn's proposal is significant (an increase in rates of at least 23 percent over 5 years) compared to the small insignificant benefit that electric customers might receive (a reduction in rates of .016 percent).

Mr. Wagner testified that the Valley Power Plant could actually operate at a minimum level of 30 megawatts (MW), however, the plant needed to run at a minimum of 40 MW to supply steam to the steam customers in the winter months. Mr. Wagner estimated that the impact of this subsidy to steam customers would be approximately $1 million.

The Commission finds it reasonable to retain the allocations as they have been since the beginning of the operation of the plant and reviewed by the Commission in 1997, and to not allocate an additional $1.0 million of fuel costs to DMS customers for the uneconomic dispatch of the additional 10MW of must-run capacity during the winter months. The Commission finds that the underlying facts of the operations at the Valley Power Plant have not changed sufficiently to warrant a change in allocation of costs associated with the operations of the plant.

Commissioner Callisto dissents.

Coal Sales Revenues

In rebuttal testimony, WEPCO witness Ms. Wolter proposed a reduction in coal sales revenue of $2.625 million to reflect an updated nomination of coal tons by the mines.
Mr. Wagner testified that the company is providing additional information that was not provided during the rate case audit. Mr. Wagner testified that the Commission in past rate cases has recognized that once the Commission staff audit is complete, audit staff does not revise its forecasted revenue requirement except for: (1) math errors; (2) effects of new laws that have actually been adopted; or (3) estimates that have been recognized as contingent on later events at the time when they may be corrected in the event that contingency occurs that resolves or

reduces the uncertainty. The Commission has also recognized that the closer to the test year, the more refined a projected income statement becomes, but for practical reasons there is a need to stop updating at some point, otherwise there would be a continual moving target.

The Commission finds it reasonable to incorporate the reduction in coal sales revenue based on the updated nomination data.

Commissioner Callisto dissents.

Cross-State Air Pollution Rule

On August 21, 2012, the District of Columbia Court of Appeals vacated CSAPR in its entirety. As such, all costs and revenues associated with CSAPR have been removed from the revenue requirement.

ERGS PROMOD Method

WEPCO has traditionally modeled its coal units as must-run reflecting how they have been offered into the MISO market. WEPCO has considered opportunities for its coal units to be offered as economic in the MISO market in order to reduce its costs of operations. During 2012, WEPCO offered its ERGS units as economic for certain periods. In this proceeding, and prospectively, it is appropriate for WEPCO's ERGS units to be modeled as economic in the MISO energy market during the non-summer months of the test year.

Elm Road Generation Station Cost Over-Run

One of the issues to be decided in this docket is the cost over-run associated with the construction of ERGS. In its Final Decision in dockets 5-CE-130 and 5-AE-118, dated November 10, 2003, the Commission authorized the construction of the ERGS units. In that decision, the Commission addressed the issue of potential construction cost over-runs. The

Commission set an authorized total cost for construction (Approved Amount) of the ERGS units of $2.191 billion. The Commission limited recovery of any prudently incurred cost over-run to 105 percent of the total authorized cost. Prudently incurred *force majeure* items are also recoverable, but are not counted in the 105 percent calculation. Based on the November 10, 2003, Final Decision, the recovery of prudent, non-*force majeure* cost over-runs is limited to $109.55 million.

Definition of *Force Majeure*

There are two definitions of *force majeure* in the record of this proceeding. One is from the Bechtel engineering, procurement, and construction (EPC) contract and the other is from the facility leases (non-EPC) approved in docket 5-CE-130/5-AE-118. The two definitions are not the same.

The Commission determines that use of the facility lease definition is consistent with its Final Decision in dockets 5-CE-130 and 5-AE-118, dated November 10, 2003, authorizing the construction of the ERGS units and determines that the relevant definition of *force majeure*, for purposes of determining the ERGS Approved Amount, is the facility lease definition.

Bechtel Settlement Agreement

On December 20, 2008, Bechtel submitted a claim for cost and schedule relief related to weather, labor, and We Power[4]-caused delays. Bechtel also reserved its rights to make additional claims.

The weather events claimed by Bechtel included: (1) exceptionally high winds affecting crane usage that Bechtel claimed seriously hindered construction activity, most notably structural

[4] We Power is a subsidiary of WEC that owns and constructed the Port Washington combined cycle units and ERGS.

steel erection; (2) an exceptionally snowy winter that occurred before the ERGS' major facilities were enclosed that Bechtel claimed seriously impacted construction activities, such as installation of large-bore pipe; and (3) unprecedented heavy rains that Bechtel claimed significantly impacted construction on the dock area where underground activities and earthwork were still underway.

The labor events claimed by Bechtel included declines in availability of craft labor, an increase in regional projects posing new competition for local labor forces, changes in requirements to attract labor such as the need to ensure substantial amounts of overtime and payment of per diem, and challenges to attracting and hiring qualified sufficient craft levels due to terms of the Project Labor Agreement that Bechtel believed made the compensation package for labor on ERGS non-competitive.

On October 30, 2009, Bechtel updated the claim to actualize the damages through ERGS Unit 1 First Fire (July 23, 2009) to a total amount of $517.3 million. We Power disputed the Bechtel claim, and was able to settle the matter prior to arbitration for $72 million.

The parties did not dispute that it was prudent to settle the $517 million claim brought by Bechtel for $72.0 million. The Commission concurs that it was reasonable and prudent to resolve this claim for $72 million. The Commission further determines that this expense is to be included in the 105 percent of the Approved Amount cost over-run limit calculation.

Bechtel Claim Defense

In response to the December 20, 2008, Bechtel claim, as updated on October 30, 2009, We Power retained various legal counsel and outside experts to dispute the claim. The cost for the legal counsel and outside experts was $12,094,893.

WEPCO witness Frederick Kuester testified that based on an analysis of the available information, We Power believed it needed a range of expertise to vigorously defend against the claim and keep the costs to WEPCO customers low.

CUB argued that because the majority of Bechtel's claim was for weather impacts, and the company had a strong defense for the labor incentives claim, it was imprudent for We Power to spend $6.8 million in litigation costs to defend against the labor incentives portion of the Bechtel Claim. CUB believes the Commission should not require ratepayers to pay the $6.8 million in litigation costs associated with the labor incentives portion of the Bechtel claim.

The Commission finds that WEPCO was obligated to defend all of the claims vigorously, and disagrees with CUB's contention that the legal fees related to defense of the labor-related claims should be excluded. WEPCO reached a global resolution of this claim for approximately 14 cents on the dollar. The Commission therefore determines that the $12,094,893 in legal costs to defend against the Bechtel claim were prudently incurred. The Commission further determines that this expense is to be included in the 105 percent of the Approved Amount cost over-run limit calculation.

ERGS Internal Legal Costs

WEPCO is seeking recovery of litigation costs associated with the ERGS WPDES permit, the vacation and reinstatement of the ERGS CPCN and defense against the Bechtel claim. This cost item relates to internal WEPCO resources. The amount at issue is $1,063,252.

Mr. Hahn testified that WEPCO has already recovered in rates the costs deemed appropriate by the Commission for WEPCO's internal litigation resources for the years in question. He believes that allowing WEPCO to recover the internal resources portion of the litigation costs for these items would lead to double-recovery by WEPCO of those costs. He argued that the Commission should not allow WEPCO to recover $1,063,252 for internal litigation resources associated with these cost overruns.

WEPCO witness David Ackerman testified that the $1,063,252 in question is not a double-recovery of WEPCO's internal litigation resources. Mr. Ackerman stated that WEPCO's test-year budgets reflect a proper allocation of internal resource costs between current period O&M expense that would be properly recovered in a prospective test year versus amounts charged to capital, intercompany, or external billable.

The Commission determines that the $1,063,252 in ERGS cost over-run associated with the internal legal cost component of WEPCO's WPDES litigation defense, CPCN litigation defense, and defense of the Bechtel claim is not a double-recovery of previously authorized labor expenses.

Commissioner Callisto dissents.

Unforeseen Sub-Surface Conditions

WEPCO stated that despite extensive soil borings taken prior to commencement of ERGS construction, areas of the site proved to have soil bearing capacities below that anticipated. As a result, certain buildings, such as the indoor coal storage facility, required more robust foundations. The amount at issue is $1,000,000.

In a WEPCO response to a CUB data request, WEPCO stated that it incurred a total cost of $11,522,060 due to unforeseen sub-surface conditions at the ERGS construction site and that $10,522,600 of that total was accounted for within the ERGS Approved Amount while the remaining $1,000,000 was not.

The parties did not contest whether it was prudent to include these costs. The Commission determines that the $1,000,000 spent to address unforeseen sub-surface conditions was prudently incurred. The Commission further determines that this expense is to be included in the 105 percent of the Approved Amount cost over-run limit calculation.

Fuel Flexibility of Units

The ERGS facility design was changed to allow future fuel flexibility. This change involved the procurement, construction, testing, and commissioning of equipment to allow the facility to be modified in the future in a way that would minimize costs and operational disruptions associated with installing coal mixing facilities and other equipment required to burn a mix of fuel types. Generally, the modifications were to the baghouse, boiler, and coal handling system. The amount at issue is $24,345,473.

WEPCO testified that in 2006, it requested that We Power undertake this modification to the ERGS units due to emerging mercury emission control technologies and increased volatility in the price of eastern bituminous coal in 2004-2006. WEPCO believes it made sense to incorporate these modifications into the ERGS units during construction because they would have been substantially more expensive to incorporate after ERGS had been fully constructed. WEPCO further believes that the ability to burn a mix of fuel types will result in significant fuel-cost savings estimated to be $25 to $50 million per year. WEPCO stated this cost was to be included in the 105 percent of the Approved Amount cost over-run limit calculation. No one disputed this.

CUB stated it believes it is possible that in the long-term, the money expended to establish the potential for fuel switching may benefit ratepayers. However, it said it is clear that ratepayers are not yet realizing any benefit from the additional investment in fuel flexibility. It states that ERGS is not yet able to burn blended or alternative fuels, and this expenditure would seem to fit best in the category of plant held for future use. It recommends that this expense be excluded from the current rate case and that WEPCO should be allowed to request recovery of this expense, plus any other prudent expenditures related to fuel flexibility, in a future rate case. Mr. Metcalfe testified that he was in agreement with deferring these costs for recovery in a future rate case. He requested that the carrying cost for the $24 million in fuel flexibility modifications, calculated in accordance with the Facility Leases, be included in rates starting in January 2013.

The Commission determines that deferring the $24.3 million already incurred for fuel flexibility, plus any other expenditures related to fuel flexibility, including carrying costs for the $24 million, for review in a future rate case is reasonable. The carrying costs shall be calculated using the short-term cost of debt. The Commission further determines that this expense is to be included in the 105 percent of the Approved Amount cost over-run limit calculation.

CPCN Vacation and Reinstatement

Several persons petitioned for judicial review of the Commission's Final Decision authorizing the construction of ERGS in Dane County Circuit Court. The circuit court vacated the Final Decision. The court's ruling was appealed. Ultimately, the Wisconsin Supreme Court reversed the circuit court and reinstated the CPCN on June 28, 2005.

Under the EPC contract for ERGS, We Power was required to issue a Full Notice to Proceed (FNTP) to Bechtel by March 15, 2005. When the circuit court vacated the Final Decision, We Power could not issue the FNTP, exposing it to specified daily increases in the EPC contract price. We Power negotiated two extensions of the deadline for the issuance of the

FNTP that included an increase in the contract price for each day of delay beyond March 15, 2005. After the Wisconsin Supreme Court reinstated the Commission's Final Decision, We Power issued the FNTP on July 29, 2005. The increased cost under the EPC contract due to this delay was $41,224,265 plus $3,637,816 in litigation expenses and costs for internal resources required to manage the project for longer than originally intended. The total amount at issue is $44,862,081.

Mr. Metcalfe testified that WEPCO did not believe that the Dane County Court would vacate the CPCN and that it would not have been reasonable to risk the project schedule and higher costs in the face of a lawsuit WEPCO believed had little merit. He also testified that it was important to execute the EPC contract when WEPCO did because the time period in question was one of escalating raw materials and equipment costs. WEPCO believes that if it had delayed signing of the EPC contract, it is likely Bechtel would have insisted on a price higher than the Commission had approved. Additionally, the ERGS Air Permit issued by the Wisconsin Department of Natural Resources (DNR) required that construction commence no later than July 14, 2005.

CUB witness Mr. Hahn testified that We Power signed the Bechtel EPC contract knowing that it might be liable for additional costs if the FNTP was not issued as scheduled and that the legal and regulatory uncertainty regarding the judicial review process could cause delays even if the CPCN was never vacated. He stated it was unreasonable for We Power to sign the EPC contract under these circumstances and that We Power did not maximize use of provisions in the contract to protect WEPCO and its ratepayers from costs associated with a delay in the FNTP. CUB argued that WEPCO had two ways to satisfy the air permit's requirement to commence construction, one of which would have allowed for a delay in signing the EPC contract until July 2005. Mr. Hahn recommended that the Commission not allow the $44.9 million in rates.

The Commission finds that the vacation of the CPCN constituted an unforeseen change in law that was beyond the reasonable control of We Power. Given what was known at the time and faced with pending litigation, a potential price increase or delay in construction, the Commission concludes that it was reasonable to enter into the EPC contract.

The Commission determines that the $44,862,081 expense caused by the delay in commencing construction due to the vacation and reinstatement of the CPCN was *force majeure* and was prudently incurred.

Army Corp. of Engineers Permit Requirements

On May 28, 2005, the U.S. Army Corps of Engineers (ACOE) issued its permit for the installation of the ERGS cooling water system and other construction-related activities. Special Condition 6 of the permit required the construction of six fish spawning reefs in Lake Michigan. Special Condition 14 of the permit required that certain measures be taken to mitigate the loss of sand caused by the placement of certain fill and structures on the bed of Lake Michigan. The amount at issue is $5,828,982.

Mr. Metcalfe testified that neither of these requirements, Special Conditions 6 and 14 of the ACOE permit, could have been reasonably contemplated at the time of the CPCN application. WEPCO, in its response to a CUB data request stated that it believed this was the first time these types of projects were required in permits issued by the ACOE St. Paul District.

CUB argued that this item is not *force majeure* because WEPCO has not shown that this cost delayed, impaired, or prevented performance by any party as required to qualify as *force majeure* under the lease agreements.

The Commission finds that ACOE's imposition of permit conditions did not constitute a change in law because it was reasonably foreseeable that the ACOE would, under then existing authority, issue a conditional permit.

The Commission determines that the $5,828,982 cost caused by the ACOE special permit conditions was not *force majeure* but was prudently incurred. The Commission further determines that this expense may be included in the 105 percent of the Approved Amount cost over-run limit calculation to the extent the addition of these costs did not result in the recovery of prudent, non-*force majeure* cost over-runs in excess of $109.55 million.

Six Mile Road Underpass

Order Point 5 of the Commission's Final Decision authorizing construction of the ERGS required WEPCO to work with the neighboring communities to mitigate valid complaints and concerns. In response to this Order Point, WEPCO entered into an agreement with the village of Caledonia that required the design and management of the rail yard serving ERGS so that all operations under its control remained north of Six Mile Road and the construction of a grade separation at the Six Mile Road railroad crossing along the then current crossing alignment. The grade separation that was authorized by the Commission's Final Decision was an off-alignment design, which was ultimately opposed by Caledonia. The design was modified to an on-alignment grade separation, as requested by Caledonia. The amount at issue is $3,567,007.

Mr. Metcalfe testified that the steps necessary to comply with the Commission's order points included designing and managing the rail yard serving ERGS so that all operations under WEPCO's control remained north of Six Mile Road and constructing an on-alignment versus an off-alignment grade separation crossing. He stated that under the definition of *force majeure* in the facility leases, this cost is the result of a change in Law *Force Majeure* event.

CUB argued that this item is not *force majeure* because WEPCO has not shown that this cost delayed, impaired, or prevented performance by any party as required to qualify as *force majeure* under the lease agreements. CUB also stated it did not believe that this event was a change in law.

The Commission finds that compliance with the Commission's order did not constitute a change in law under the *force majeure* definition.

The Commission determines that the $3,567,077 cost caused by the modification to the railroad crossings in the village of Caledonia was not a *force majeure* event, but was prudently incurred. The Commission further determines that this expense may be included in the 105 percent of the Approved Amount cost over-run limit calculation to the extent the addition of these costs do not result in the recovery of prudent, non-*force majeure* cost over-runs in excess of $109.55 million.

Compliance with WPDES Settlement

On March 30, 2005, the DNR issued a WPDES permit (permit) for ERGS that included requirements based on EPA Section 316(b) (316(b)) that was used as guidance by the DNR. In January 2007, the U.S. Court of Appeals for the Second Circuit decision in *Riverkeeper, et al. v. USEPA (Riverkeeper II)* remanded portions of the 316(b) regulations governing cooling water intake structures at existing facilities to the EPA for reconsideration. As a result of the *Riverkeeper II* decision, certain conditions in the ERGS permit were challenged in administrative proceedings. The Administrative Law Judge (ALJ) issued a decision upholding DNR's decisions, but the ALJ's decision was challenged in judicial proceedings. The Dane County circuit court ultimately issued a Decision and Order affirming the ALJ's decisions, but remanded the challenged conditions, directing that they be reconsidered in light of the *Riverkeeper II* decision. WEPCO ultimately settled the dispute. The total estimated cost of compliance with the WPDES settlement is approximately $177 million. This total cost consists of expenses associated with projects relating to Lake Michigan water quality, the installation of 15 MW of solar generation (authorization of 5 MW of the 15 MW is requested in this docket), and support of long-term greenhouse gas emission reductions.

WEPCO included the legal cost associated with the WPDES challenge and settlement as part of the ERGS cost over-run. However, the actual cost to WEPCO of compliance with the WPDES settlement was not included.

Mr. Kitsembel testified that if the WPDES settlement and its associated cost was necessary for the project to proceed without additional delay, the Commission may wish to include the cost of WPDES compliance it finds reasonable as part of the total ERGS cost over-run for the purpose of determining what is recoverable in rates under the 105 percent cost limit, using Financial Accounting Standards Board Statement (FASB) 71. He further testified that he believed that the costs associated with the Lake Michigan water quality and long-term greenhouse gas emission reduction efforts could be included in the ERGS cost over-run for purposes of determining recoverability in rates under the 105 percent cost limit. The amount at issue could be as much as $102 million.

WEPCO witness Mr. Ackerman testified that there are several problems with Mr. Kitsembel's suggestion. He also testified that FASB 71 does not apply to an unregulated company (We Power). He testified that, instead, the Commission should continue to look at the annual payments under the WPDES settlement agreement on a rate case by rate case basis.

The Commission determines that the annual payments under the WPDES settlement agreement will be reviewed on a rate case by rate case basis. The Commission further determines that it is not reasonable to allow the annual expense associated with the WPDES settlement agreement in the electric rates for 2013 and 2014.

Commissioner Callisto dissents on exclusion of the expenses from electric rates in 2013 and 2014.

Defense of WPDES Lawsuit

The legal fees associated with the defense of the WPDES lawsuit amount to $4,956,127 million. WEPCO witness Mr. Metcalfe testified that WEPCO incurred legal costs and expert witness expenses defending the ERGS WPDES permit against administrative and judicial challenges. Mr. Ackerman testified that the legal costs associated with obtaining the ERGS WPDES permit were capitalized by We Power because the permit was integral to the plant. He further testified that an alternative approach to capitalizing this expense would be for WEPCO to include the WPDES legal costs as part of the PTF escrow because the WPDES permit is related to the operations of the plant.

WEPCO was obligated to defend the WPDES lawsuit, and the permit was integral to the plant. The Commission determines that deferring the $4,956,127 in legal expense associated with the WPDES settlement agreement, for review in a future rate case proceeding is reasonable.

Hexavalent Chromium Rule

On February 28, 2006, OSHA issued a final rule addressing occupational exposure to hexavalent chromium, which became effective on May 30, 2006. This rule significantly reduced the permissible exposure limit and action level for hexavalent chromium, and the rule required exposure assessments and the implementation of additional measures by Bechtel, its subcontractors, and suppliers in connection with the ERGS project. The additional measures included engineering controls, respiratory protection, protective work clothing and equipment, medical surveillance, and communication of hazards for workers involved in tasks that may cause exposure to hexavalent chromium. The amount at issue is $10,000,000.

WEPCO stated that it believed this was a change in law *force majeure* event. CUB stated that WEPCO provided information indicating that costs associated with the hexavalent chromium rule were incurred as a result of an event that prevented or delayed performance of obligations and therefore did not contest the finding of *force majeure*.

The Commission determines that the cost of $10,000,000 caused by OSHA's decision to change the administrative rule governing exposure to hexavalent chromium was the result of a change in law *force majeure* event and was prudently incurred.

Mercury Continuous Emission Monitoring System

On May 15, 2005, EPA published the Clean Air Mercury Rule and established standards of performance for mercury emissions from new and existing coal-fired electric utility units.

New coal-fired power plants (construction starting on or after Jan. 30, 2004) were required to meet stringent new source performance standards (NSPS) and were subject to emission caps. Under the revised NSPS standards, units that commenced commercial operations on or after July 1, 2008, were required to install and certify mercury monitoring systems by the later of January 1, 2009, or 90 operating days or 180 calendar days, whichever occurred first, after the date on which the unit commenced commercial operations. The amount at issue is $851,000.

WEPCO witness Mr. Metcalfe testified that due to the new EPA requirements, ERGS incurred additional costs to install and certify mercury emission monitoring systems. WEPCO stated these costs were the result of a change in law *force majeure* event and were prudently incurred.

CUB argued that this item is not *force majeure* because WEPCO has not shown that this cost delayed, impaired, or prevented performance by any party as required to qualify as *force majeure* under the lease agreements.

The Commission finds that the Clean Air Mercury Rule constituted a change in law that either materially impacted or delayed performance under the EPC contract.

The Commission determines that the $851,000 cost caused by EPA's requirement regarding mercury emission monitoring was *force majeure* and was prudently incurred.

State Unemployment Insurance Cost Over-Run

A modification in Wisconsin's payroll tax law went into effect on January 1, 2009. This modification increased the taxable wage base, per employee, that was subject to the State Unemployment Insurance (SUI) tax from $10,500 to $12,000. It also adjusted the apportioning of the basic rate and the solvency rate in calculating a company's total rate. When applied, this modification resulted in a higher SUI rate and costs in 2009 and 2010. The amount at issue is $1,813,000.

Mr. Metcalfe testified that in 2009, the state of Wisconsin enacted a change in payroll tax law resulting in additional cost to ERGS. WEPCO argues that the $1,813,000 cost caused by the change in Wisconsin payroll tax law was the result of a change in law *force majeure* event and was prudently incurred.

CUB argued that this item is not *force majeure* because WEPCO has not shown that this cost delayed, impaired, or prevented performance by any party as required to qualify as *force majeure* under the lease agreements.

The Commission finds that the modification to Wisconsin's existing payroll tax law did not constitute a material change in law or materially impact performance under the EPC contract.

The Commission determines that the $1,813,000 cost caused by the change in the Wisconsin payroll tax law was not *force majeure* but was prudently incurred. The Commission further determines that this expense may be included in the 105 percent of the Approved Amount cost over-run limit calculation to the extent the addition of these costs do not result in the recovery of prudent, non-*force majeure* costs in excess of $109.55 million.

July 2010 Storms

On July 22 and 23, 2010, the site experienced in excess of five inches of rain within the two-day period, including totals in a 24-hour period that were in excess of the ten-year record for the area. As a result of these heavy rains, extensive erosion and sediment accumulation occurred at the site requiring a significant repair and cleanup effort. Bechtel experienced excessive absenteeism of manual craft employees, was required to divert resources to address immediate storm cleanup, and also experienced delays in materials deliveries and vendor technical assistance and support. The amount at issue is $630,000.

WEPCO states that this expense was the result of a weather *force majeure* event, and these additional costs were prudently incurred in order to address the consequences of these unusually heavy rainstorms.

CUB states that WEPCO provided information indicating that the cost associated with these severe weather events was incurred as a result of an event that prevented or delayed performance of obligations and therefore did not contest the finding of *force majeure*.

The Commission determines that this cost was the result of a weather *force majeure* event and was prudently incurred.

Other *Force Majeure* Events

A number of miscellaneous events during construction resulted in minor impacts to the cost of ERGS. The events include the interruption of material and equipment deliveries due to Hurricane Ike, a volcanic eruption in Iceland, and a labor strike at the site of the waste-handling contractor, Waste Management. The amount at issue is $438,515.

Mr. Metcalfe testified that a number of miscellaneous events added to the cost of the project. WEPCO stated that these costs were caused by *force majeure* events as defined by the facility leases and were all prudently incurred.

CUB argued that for the Waste Management strike and the Bowl and Dock fire protection costs ($370,170 in total), WEPCO has not shown that these costs delayed, impaired, or prevented performance by any party as required to qualify as *force majeure* under the lease agreements. Therefore, only $68,345 qualifies as *force majeure*.

The Commission determines that the Bowl and Dock fire protection issues were not *force majeure*, leaving only $137,980 as *force majeure*. The Commission also determines that the entire $438,515 was prudently incurred. The Commission further determines that the $300,535 in prudent, non-*force majeure* expense is to be included in the 105 percent of the Approved Amount cost over-run limit calculation.

Low-Pressure Turbine Corrosion

Unusual deposits were discovered on the ERGS Unit 1 LP turbine blades. This finding led to the cleaning of the Unit 1 turbines and the replacement of certain blades. The issue also affects Unit 2 and will be addressed during a late 2012 outage. WEPCO states its belief that the cost associated with this issue is the responsibility of Bechtel. This issue is not settled, as Bechtel believes WEPCO should be responsible for the cost associated with the LP turbine repair.

Mr. Kitsembel testified that if, when this issue is ultimately resolved, WEPCO is responsible for all or a portion of the low-pressure turbine repair cost, the amount WEPCO is responsible for should also be included in the ERGS cost over-run total. The cost is unknown, but could be several million dollars. The issue of whether to allow WEPCO recovery of any prudently incurred low-pressure turbine repair cost may need to be addressed in a future rate case proceeding.

Mr. Metcalfe testified that WEPCO only became aware of the turbine corrosion issue after turnover of the ERGS units. The issue is being handled under the warranty provisions of the EPC Contract. Warranty rights have been assigned to WEPCO. WEPCO is involved in a dispute with Bechtel on this matter and is seeking to recover its costs accordingly. To the extent it is unable to fully recover its costs, WEPCO believes these costs should be escrowed and form part of a future rate proceeding subject to a prudence determination at that time.

The Commission determines that because the cost issue associated with the low-pressure turbine corrosion is not yet resolved, the cost may be escrowed and be part of a future rate proceeding and subject to a prudence determination at that time.

Other Cost Items

WEPCO set out approximately $8.71 million in forecast cost that had not been incurred as of February 29, 2012. This includes expenses such as payments due upon final acceptance of ERGS Units 1 and 2, We Power costs, punch list items for units 1 and 2, and costs associated with final project cost review.

Mr. Kitsembel testified that, as with the low-pressure turbine issue, this amount should also be included in the ERGS cost over-run total and that the issue of allowing recovery of any of these costs may need to be addressed in a future rate case proceeding.

The Commission determines that ERGS cost items not yet settled, such as punch list and final cost review items, should be part of a future rate proceeding and subject to a prudence determination at that time.

Number of Employee Positions

During its audit in this proceeding, Commission staff compared the company's filed estimate of average test-year employee positions to actual average employee positions for the 2008, 2010, and 2012 (through May) test years. Using a simple average of the variance percentages for each test year, and subsequently modified after discussions with the company, Commission staff reduced the company's filed level by 186 positions for WEPCO and by

17 positions for WG's test-year payroll. In surrebuttal testimony, Commission staff witness Mary Kettle suggested that it may be reasonable for the Commission to add back 105 union positions for WEPCO to get staff's employee position level for WEPCO's union and non-union employee category to the actual average level for 2012 through May.

Wisconsin Industrial Energy Group (WIEG) noted that WEPCO has historically overstated its level of employee positions. WIEG recommended a reduction of $10.539 million to WEPCO's electric payroll expense, associated employee benefits, and payroll taxes to reflect this historical variance.

The company disagreed with any adjustment to its filed level of employee positions because the years used in the budget-to-actual analysis were recessionary years and the company stated that it needed to manage its costs in the face of falling revenues. The company presented testimony from several witnesses describing the negative consequences that would result if the company's filed level of employees was reduced.

The Commission finds that Commission staff's reductions to the company's forecast of average employees with 105 union employees added for WEPCO is reasonable. The company has forecasted significantly more employee positions than it has filled for the last three test years. It is reasonable to rely on these historical variances to forecast a reasonable level of employee positions in the test year. The reasonable test-year forecast of employee positions is 4,179 for WEPCO and 449 for WG.

This reduction in the level of employee positions reduces the company's revenue requirement by $4.9 million for WEPCO and by $0.5 million for WG. The Commission also limited wage increases to 2.3 percent and 1.9 percent for 2012 and 2013, respectively, for all non-union employees. Union employees were limited to those percentages for any non-contractual portion of the forecast period. The total reduction to the company's filed payroll estimate is $5.7 million for WEPCO and $0.4 million for WG on a Wisconsin retail basis.

Non-Labor Production and Distribution Expenses

In this proceeding, Commission staff performed a budget-to-actual analysis on certain functional areas of each utility. These adjustments were limited to the production and distribution functions. The most significant adjustments were to the company's non-labor production and distribution O&M expenses for WEPCO's electric utility. Staff compared the estimates filed by the company for the 2008 and 2010 test years to the actual levels for those years and found that the company spent significantly less than its estimates in these two areas for both test years. Commission staff also compared the company's 2009 actual levels to the 2008 test-year estimates filed by the company and compared the company's 2011 actual levels to the 2010 test-year estimates filed by the company to see if the variances were different in the second year of each biennium. The company spent less than its estimates for both of those years as well in both the production and distribution functions. Thus, the company spent significantly less than it estimated in each year from 2008 through 2011 for non-labor production and distribution O&M for WEPCO's electric utility.

The Commission finds that it is reasonable to reduce the company's filed estimates of non-labor production and distribution expense to reflect historical under-spending. The Commission accepted Commission staff's proposed reduction to non-labor electric production O&M, reducing WEPCO's electric revenue requirement by $9.8 million. For non-labor distribution expense, the Commission reduces the company's filed estimate by 75 percent of

Commission staff's adjustment, a reduction of $5.2 million to WEPCO's electric revenue requirement. The Commission acknowledged the company's historical under-spending in electric distribution, but did not approve one-quarter of the adjustment, acknowledging that the company may need to address its aging infrastructure.

Commissioner Callisto dissents on the level of non-labor electric distribution O&M to include in the test-year revenue requirement.

Transmission Escrow

In this proceeding, the company requested to reinstate its transmission escrow for prospective billings from ATC and MISO and to set transmission expense in the test year equal to the amount included in rates in the 2010 test year. The company's proposal would result in the deferral of increases in transmission billings over the 2010 level. ATC currently has plans to construct a new transmission line in southeastern Wisconsin that may lead to more competitive and lower generation costs for WEPCO in the future. Deferring incremental transmission costs now would allow those cost increases to be offset to some degree by the expected generation savings in the future.

ATC, whose costs comprise the vast majority of WEPCO's transmission costs, provides an update for the upcoming year in October of each year. Commission staff compared the as-ordered levels of non-payroll transmission expense, which includes the October update information, for 2008 and 2010 to the actual level of expense for each year. The analysis showed that the company's as-ordered level of transmission expenses from the 2008 test year was significantly greater than actual expense for 2008 and 2009, but the as-ordered level from the 2010 test year was slightly less than actual expense for 2010 and 2011 because ATC made improvements to its budgeting process for the 2010 budget. The most significant change was to use the most recent rolling twelve months to measure its customers' load ratio share (LRS) rather than using the most recent calendar year. The LRS is used to allocate ATC's costs among its customers. This change resulted in a better allocation of forecasted costs to individual customers.

Thus, the Commission finds it reasonable to use the company's revised estimate of transmission expenses for 2013 and 2014 which include ATC's October 2012 update. The company estimates that transmission expenditures for 2013 and 2014 will be $286,198,240 and $311,155,853, respectively, on a total company basis, or $264,132,356 and $287,165,737, respectively, on a Wisconsin retail basis. The company will record $250,738,748 in expense on a Wisconsin retail basis until the Commission authorizes the company to record a different amount as transmission expense. This will result, on a forecasted basis, in WEPCO deferring an estimated $32.4 million in 2013 and an additional $23 million in 2014 on a total company basis for a total estimated deferral of $55.4 million over two years.

The Commission finds it reasonable to reinstate the transmission escrow on a temporary basis and to set the associated carrying costs at the short-term debt rate. Carrying costs shall be accrued into the deferred balance.

Uncollectible Accounts

Commission staff used the percentage of net write-offs to revenue to forecast escrowed uncollectible accounts expense. Staff used a three-year average of this percentage to forecast net write-offs for WEPCO's electric operations and for WG because the historical percentages did not show a trend. For WEPCO's gas operations, the percentage of net write-offs to revenue showed a decreasing trend so staff used a trended percentage to forecast the test year.

The company disagreed with Commission staff's methodology and believed that staff should have used the average percentage of net write-offs to revenue for WEPCO's gas operations, just as it did for WEPCO's electric operations and for WG. The Commission agrees with the company.

For non-escrowed uncollectible accounts expense, Commission staff's estimate was based on a review of historical levels. The company argued that staff's estimate was 44 percent lower than the three-year average and the company's estimate is 27 percent lower than the three-year average, which is already a conservative estimate. The Commission finds that the company's test-year estimate of non-escrowed uncollectible accounts expense is reasonable.

The company requested to continue escrow accounting for its residential uncollectible accounts expenses due to the uncertain pace of the state's economic recovery and the corresponding uncertain impact on customers. Considering that impacts of the poverty levels and higher unemployment rates in We Energies' service territory compared to the rest of the state, the Commission finds it reasonable to continue escrow accounting for residential uncollectible accounts expenses of WEPCO and WG.

Accordingly, the company is directed to record $26,809,000 in uncollectible accounts expense for WEPCO electric, which is comprised of $25,252,000 in estimated net write-offs plus an amortization expense of $1,557,000. For WE-GO, the company shall record $1,622,000 in uncollectible accounts expense, which is comprised of $3,909,000 in estimated net write-offs less a negative amortization expense of $2,287,000. For WG, the company shall record

$2,808,000 in uncollectible accounts expense, which is comprised of $17,764,000 in estimated net write-offs less a negative amortization expense of $14,956,000. These expense amounts, which are Wisconsin retail amounts, shall be recorded annually until the Commission authorizes a different amount to be recorded.

Employee Benefits

Commission staff made downward adjustments to employee medical expenses, dental expenses, and post-retirement benefits other than pension expense (SFAS No. 106). Commission staff used a three-year average to forecast test-year medical and dental expenses because these expenses have been flat or declining over that period. For post-retirement benefits other than pension expense, Commission staff used an average annual growth rate to forecast the test year because there was a slightly increasing trend.

The company disagreed with Commission staff's forecast of these items because staff did not consider significant factors that affect the cost of these items. The company argued the critical importance, when forecasting health care costs, of forecasting how many employees will be covered and the cost per employee, which staff acknowledges it did not do. The company argued similar flaws existed in staff's dental and post-retirement welfare costs forecasts. Finally, the company argued staff wrongly appeared to conclude zero growth in health care costs, despite what the company contends is a consensus view that recent federal health care legislation will increase near-term health care costs.

The Commission finds the company's forecasts to be reasonable for employee medical, dental, and post-retirement benefits other than pension expense.

Commissioner Callisto dissents.

Board of Directors Expense

Commission staff reduced the company's filed estimate of test-year Board of Directors expense, in part, to eliminate stock-based compensation. The Commission has historically not allowed rate recovery of stock-based compensation because it is not in the best interest of ratepayers as it may prompt too great a focus on earnings rather than maintaining and improving the safety and reliability of the company's operations.

The company disagreed with this portion of staff's adjustment on the basis that the stock-based compensation is really a director retainer fee paid in stock. The company stated that the stock compensation is a substitute for cash and that paying directors in stock rather than cash should instill a long-term incentive to make decisions that ensure the long-term financial health of the company.

The Commission finds that it is reasonable to reduce the company's test-year estimate of Board of Directors expense to exclude stock-based compensation because it could provide an incentive for directors to act in ways that may not be in the best interests of the ratepayers. It is also reasonable to exclude the cost associated with the directors' charitable award. The total reduction to the Board of Directors costs is $707,000 for WEPCO and $117,000 for WG on a Wisconsin retail basis.

Chairperson Montgomery dissents.

PTF Escrow Adjustment

During the staff audit in this proceeding, it was discovered that WEPCO had charged $618,000 to the PTF escrow since its inception for employee bonuses and incentives. WEPCO shall reduce the balance of its PTF escrow at the beginning of the test year by $618,000 to remove bonuses and incentives charged in error to the escrow, as well as reducing the return on net working capital to reflect the lower average balance of the deferred amount.

Electric Gross Receipts Tax

The gross receipts tax (GRT) expense in any given year is based on the prior year's revenue. The company's filed forecast of electric GRT expense incorporated the test-year 2013 forecast of electric operating revenues as a proxy for 2012 operating revenues in the calculation of the forecasted expense. Commission staff reviewed the company's calculation used to forecast the 2013 electric GRT expense and accepted the forecasted expense of $88,157,000.

In rebuttal testimony, the company argued that the GRT should be increased in 2013 by $2.6 million to account for the higher electric sales anticipated in 2012 due to an unusually warm, dry summer. The Commission agrees that a new higher sales forecast was appropriate to forecast the test-year electric gross receipts tax.

Commissioner Callisto dissents.

WE-GO and WG Remainder Assessment

Commission staff based its test-year estimates of the remainder assessment for WE-GO and WG by multiplying the respective forecasted revenues subject to the remainder assessment by a forecasted remainder assessment factor equivalent to the 2011 factor. The companies argued that Commission staff's PSC remainder assessment adjustments were unreasonable in view of actual assessments over the past six years, and should be rejected. The Commission finds it is reasonable to use the most recent three-year average actual costs to forecast the test-year remainder assessments for WE-GO and WG.

Commissioner Callisto dissents.

Deferred DOE Litigation Expenses

The Final Decision in WEPCO's fuel case, docket 6630-FR-103, dated January 5, 2012, authorized no change in 2012 rates as a result of offsetting the forecasted 2012 fuel increase of $26.2 million (Wisconsin retail) against a DOE net settlement refund of approximately the same amount. This settlement was related to WEPCO's claim for partial breach of contract for failure to pick up spent nuclear fuel (SNF) at the Point Beach Nuclear Power Plant. The Commission ordered WEPCO to track the amount of actual DOE settlement refund returned to Wisconsin retail ratepayers, to defer any material over- or under-collections to ratepayers to a future rate proceeding, and found it appropriate to defer the determination of appropriate litigation costs related to the DOE settlement to the next rate proceeding. These deferred litigation expenses are associated with the DOE settlement refund for partial breach of a contract to pick up SNF at the Point Beach Power Plant that were netted against the DOE settlement and applied to offset the 2012 fuel increase in docket 6630-FR-103. Commission staff has reviewed the litigation expenses in this proceeding totaling $13.6 million and Commission staff witness Candice Spanjar testified that $48,000 in employee expenses and catering expenses was questionable.

Based on its discovery requests in docket 6630-FR-103, CUB believes that, at a bare minimum, the amount should be reduced by $42,000 for costs from the law firm of Piper, Marbury, Rudnic that were unrelated to DOE SNF litigation. However, CUB believes the amount should be reduced by considerably more because WEPCO did not prudently manage and control the expenditure of these outside litigation costs.

The Commission finds that it is appropriate to disallow $90,000 of deferred litigation expenses from future rates because these costs were either unrelated to the DOE litigation, or otherwise questionable expenses. It is also reasonable to continue reviewing the deferred litigation expenses and address this issue in the next annual fuel reconciliation.

Production Tax Deduction

In the company's last full rate case proceeding in docket 5-UR-104, the Commission indicated it was reasonable to continue the escrow for the domestic production activities deduction, also known as the Section 199 deduction, but it should be reevaluated in the company's next rate proceeding. This item was escrowed at the request of WEPCO because it was difficult to accurately forecast at that time.

The company believes that the Section 199 deduction continues to be difficult to accurately forecast because it is a deduction that essentially is determined after all other items of taxable income have been determined. While WEPCO has not claimed a Section 199 deduction in 2011, nor does it expect to file any in 2012 and 2013 due to actual or projected net operating losses primarily related to bonus depreciation claimed, once the bonus depreciation effect is gone, the company estimates that the Section 199 deduction will once again be very difficult to forecast with any precision. The Commission finds that it is reasonable to continue escrow accounting treatment of the Section 199 production tax deduction.

WPDES Settlement Funding

The 2010 test-year order in docket 5-UR-104 approved the recovery of the company's portion of the 2011 payment to fund projects related to water quality impacts in Lake Michigan levelized over the two-year period of 2010 and 2011. The annual recovery was set at half of what the company's actual annual funding payments would be starting in 2011. The company's subsequent 2012 test-year order was based on a limited review that resulted in adjusting certain regulatory amortizations without any rate adjustment, and did not increase recovery of the Lake Michigan funding amount required by the agreement between the company and Clean Wisconsin and the Sierra Club. In this rate proceeding, WEPCO requested authorization to create a regulatory asset for the retail portion of the 2012 Lake Michigan funding amount and amortize the asset in 2013 and 2014. While the 2012 rate case proceeding in docket 5-UR-105 did not specifically address the recovery of the additional half, this was a settled case in which We Energies proposed an alternative approach to a traditional rate case proceeding involving no increase to its 2012 base rates and deferring $148 million of amortization expenses. In the utility's request for consideration of its alternative rate proposal in docket 5-UR-105, the company acknowledged that its decision to forgo any rate increase in 2012 would involve very real costs for the company, which it would have to manage in 2012. The Commission does not find it appropriate to create a regulatory asset for the one-half of the retail portion of the 2012 Lake Michigan funding amount related to the settlement agreement with Clean Wisconsin and the Sierra Club.

Deferral Amortizations

The Final Decision in docket 5-UR-104 authorized an annual $1,939,000 amortization of deferred carrying costs on the previously deferred Section 199 tax benefit amount over two years, such that the deferred amount would go to zero by the end of 2011. The Commission also previously authorized amortization of deferred coal legal costs that were to zero out at the end of 2011. WEPCO continued both amortizations into 2012 and proposed to amortize a 2012 estimated Section 199 deferred carrying cost balance of $1,939,000 over six years and an estimated 2012 negative deferred coal legal costs balance of $1,182,000 over two years.

Commission staff proposed eliminating both the Section 199 amortization of deferred carrying costs and the deferred coal legal costs from 2013 amortizations. Elimination of these deferred balances and test-year amortizations results in a net addition to revenue requirement of $268,000 in the test year and results in an overall reduction to revenue requirement over the next six years of $757,000.[5]

When We Energies proposed an alternative approach to a traditional rate case proceeding in docket 5-UR-105 for the 2012 test year, it proposed and the Commission authorized its request to defer $148.1 million of costs that were currently being amortized. Neither of the amortizations for the Section 199 deferred carrying costs or the deferred coal legal costs were suspended or modified by the 2012 test-year order, and the Commission did not indicate it was changing authorized amortizations of deferred amounts other than the deferral of the specific amortizations amounting to $148.1 million. Therefore, the Commission finds it appropriate to eliminate the deferred balances and test-year amortizations associated with Section 199 deferred carrying costs and deferred coal legal costs.

Section 1603 Renewable Energy Treasury Cash Grant

WEPCO expects to receive a treasury grant[6] in early 2014 for the Rothschild renewable energy biomass facility that is forecasted to go into service in the fourth quarter of 2013. WEPCO proposed to flow through a large portion of the revenue requirement impact of the treasury grant as a bill credit to customers in 2013, and a smaller portion in 2014, such that the non-fuel related electric deficiencies are normalized between 2013 and 2014. The treasury grant

[5] Elimination of the Section 199 deferred account balance of $1,939,000 netted against the elimination of the deferred coal legal costs account balance of ($1,182,000) equals $757,000.
[6] This treasury grant will be available under the American Recovery and Reinvestment Act of 2009 (ARRA) after the Rothschild biomass project goes into service.

is estimated to provide a favorable revenue requirement impact totaling about $80 million on a Wisconsin retail electric basis.[7] WEPCO proposed to account for the treasury grants as follows:

- The award is a government grant related to the construction of a capital asset and is not an investment tax credit.
- WEPCO will recognize a receivable related to the ARRA grant when it has the unconditional right to receive the cash.
- Prior to considering the effect of rate-regulation, WEPCO will recognize the ARRA grant in income when the conditions necessary to be entitled to the grant are fulfilled, which is when the capital asset is placed into service.
- After considering the effect of rate-regulation, WEPCO will recognize a regulatory liability for the commitment to reduce rates to its customers.
- WEPCO will classify the ARRA grant as a gain within the statement of operations.

The parties to this case and Commission staff did not disagree with WEPCO's decision to use the treasury grant related to the Rothschild biomass facility in lieu of the investment tax credits (ITC) or production tax credits (PTC). However, WIEG disagreed with the methodology that WEPCO proposed to use to quantify the treasury grant and related revenue requirement in that the company's methodology would have customers pay income taxes related to the treasury grant up front in 2013 and 2014, instead of over the life of the facility. However, the company's methodology reflects the net benefit (including the net income tax benefit) of the treasury grant by matching the proposed ratemaking benefit with the recognition within the financial statements. WIEG's proposed methodology to quantify the treasury grant would require the creation of a regulatory asset in addition to the regulatory liability that will be created under the company's proposal with additional carrying costs associated with the deferred asset.

Commission staff did not oppose the company's proposed accounting treatment for the treasury grant and did not oppose the company's proposed methodology for recognizing the

[7] The exact amount of the treasury grant proceeds will be known after the Treasury certifies the final costs of the project.

income tax expense associated with the tax basis reduction for both financial reporting and ratemaking purposes. However, Commission staff witness Ms. Spanjar suggested that the estimated carrying costs of $1.2 million on a Wisconsin retail basis that will result from the 2014 average deferred tax liability balance estimated at $12.6 million on a Wisconsin retail basis be included as a reduction to the 2014 step-increase.

The Commission finds that it is reasonable to apply the Wisconsin retail portion of the revenue requirement impacts associated with the treasury grant estimated as the company has proposed at $80 million between 2013 and 2014 electric revenue deficiencies as bill credits such that the non-fuel increases are approximately equivalent in both years. In addition, the Commission finds it is reasonable to reduce the 2014 step-increase by $1.2 million to reflect the Wisconsin retail revenue requirement reduction for the carrying cost benefit associated with the resulting deferred tax liability in 2014.

Due to the uncertainty of the exact amount of the treasury grant and the timing of the flow-through of the benefits to customers through bill credits on a volumetric basis, the Commission also finds that escrow accounting treatment for this item is appropriate.

2014 Electric Step-Increase Request

WEPCO requested a step-increase in electric non-fuel base rates of $37.4 million, or 1.3 percent, in 2014 primarily to reflect the Rothschild renewable energy biomass facility and a new solar project estimated to go into service in the fourth quarter of 2013. The requested step-increase also includes a reduction to bill credits in 2014 for Section 1603 renewable energy treasury grants proposed by the company to be included primarily in 2013 rates and the remaining smaller portion in 2014 rates. The Commission finds it reasonable to authorize a 2014 electric increase in the amount of $73,442,000 on a Wisconsin retail basis.

The Commission-authorized increase for 2014 incorporates several adjustments. First, it is reasonable to reduce the 2014 step-increase to reflect the Wisconsin retail revenue requirement reduction for the carrying cost benefit associated with the deferred tax liability that results from the treasury grant in 2014 as discussed in the previous section. Second, the Commission finds it is appropriate to adjust the 2014 revenue requirement associated with the Rothschild plant for the updated economic cost of capital and to correct for estimated revenues that will be received from Domtar under the capital component of the steam supply agreement. Third, according to the Commission order in docket 6630-CE-305, WEPCO notified the Commission that they would reduce the capital costs of the project allocated to the electric output of the plant by an additional $10 million to reduce the costs of the project borne by the ratepayers in its letter dated June 24, 2011. The Commission finds it is appropriate to adjust the 2014 revenue requirement to incorporate this reduction. Prior to implementation of the 2014 electric rates, the Commission finds it is reasonable to require WEPCO to provide a summary of actual costs related to the Rothschild biomass construction project. Lastly, the Commission does not find it reasonable to include the cost of the solar project in 2014 rates because it is not needed to serve load nor is it being completed to meet the Renewable Portfolio Standard.

Commissioner Callisto dissents on the disallowance of recovery for the solar project in 2014.

2014 Steam Increases

WEPCO proposed to spread the 2013 steam utility increases for VA Steam operations and MC Steam operations over the biennial rate case period. The 2014 increase requested for each of the steam utility operations is not related to incremental 2014 cost increases, but is rather merely spreading the 2013 revenue deficiencies over two years. The Commission finds it reasonable to spread the 2013 revenue deficiencies over 2013 and 2014.

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 2013 test year, which the Commission finds reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

	WEPCO				
	Electric (000's)	Natural Gas (000's)	Downtown Milwaukee Steam (000's)	Wauwatosa Steam (000's)	WG Natural Gas (000's)
Operating Revenues:					
Sales Revenues	$2,767,101	$419,849	$20,937	$14,858	$624,249
Other Operating Revenues	105,368	1,391	-49		4,544
Total Operating Revenues	2,872,469	421,240	20,888	14,858	628,793
Operating Expenses:					
Fuel & Purchased Power	1,014,626			6,119	
Purchased Gas Expense		249,868			347,780
Other Production Expenses	559,214	1,224			661
Steam Generation				4,514	
Generation Transfer			7,376	-2,173	
Gas Supply and Storage Expenses		2,017			1,488
Transmission Expenses	252,654	113			56
Distribution Expenses	90,667	22,993	5,966	846	32,712
Customer Accounts Expenses	58,192	10,893	10	7	22,506
Customer Service Expenses	61,012	20,645	22	13	23,829
Administrative & General Expenses	170,050	18,663	2,838	2,323	26,673
Total Operation & Maintenance Expenses	$2,206,415	$326,416	$16,212	$11,649	$455,705
Depreciation/ Amortization Expense	229,817	29,508	2,300	1,321	40,359
Taxes Other Than Income Taxes	119,527	6,787	1,038	897	10,467
Income Taxes	-51,631	-7,937	-92	-65	25,105
Deferred Tax Expense	121,927	27,621	304	215	17,042
Investment Tax Credits	-865	-25	-4	-3	-57
Total Operating Expenses	2,625,190	382,370	19,758	14,014	548,621
Net Operating Income	$247,279	$38,870	$1,130	$844	$80,172

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 2013 test year, which the Commission finds reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

	WEPCO				WG
	Electric (000's)	Natural Gas (000's)	VA Steam (000's)	MC Steam (000's)	Natural Gas (000's)
Utility Plant in Service	$7,807,198	$1,012,187	$69,332	$37,583	$1,577,794
Less: Accumulated Reserve for Depreciation	2,844,201	582,308	41,503	16,787	799,376
Net Utility Plant	4,962,997	429,879	27,829	20,796	778,418
Add: Natural Gas in Storage		25,200			39,067
Fuel Inventory	173,400		6,666	4,358	151
Materials and Supplies	95,062	8,290	1,231	805	4,013
Less: Accumulated Deferred Income Taxes	1,260,384	90,084	6,468	3,731	150,994
Customer Advances – Net	42,660	2,320	57		5,856
Average Net Investment Rate Base	$3,928,415	$370,965	$29,201	$22,228	$664,799

Energy Efficiency

It is reasonable for the company 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. For WEPCO electric, the company should record $45,848,000 of expense, which consists of $33,108,000 of estimated expenditures and $12,740,000 of amortization of overspent amounts. For WE-GO, the company should record $14,772,000 of expense, which consists of $10,436,000 of estimated expenditures and $4,336,000 of amortization of overspent amounts. For WG, the company should record $14,304,000 of expense, which consists of $12,745,000 of estimated expenditures and $1,559,000 of amortization of underspent amounts.

WEPCO proposed a 2013 test-year conservation escrow budget of $45,632,000, with $35,196,000 allocated to electric operations and $10,436,000 allocated to natural gas operations. WEPCO's proposed conservation escrow budget includes funding for 2005 Wisconsin Act 141 (Act 141) required energy efficiency and renewable resource programs, voluntary utility programs, and customer service conservation activities and services. The appropriate WEPCO 2013 conservation escrow budget is $43,544,000, with $33,108,000 allocated to electric operations and $10,436,000 allocated to natural gas operations. This conservation escrow budget reflects an adjustment of $384,148 to electric operations for Act 141 required energy efficiency programs. It also reflects adjustments of $240,000 and $1,464,000, respectively, to remove load-management and Farm Rewiring Program expenditures from the conservation escrow budget. In its Order in docket 5-BU-102 (PSC REF#: 168310), dated July 13, 2012, the Commission provided a definition of customer service conservation activities and services for which conservation escrow treatment is appropriate. WEPCO's load-management and Farm Rewiring expenditures do not meet this definition. It is appropriate to fund load-management and Farm Rewiring activities through non-escrow O&M.

The appropriate conservation escrow budget for WG is $12,745,000. This includes funding for Act 141 required energy efficiency programs, voluntary utility programs, and customer service conservation activities and services.

Renewable Energy Development Program

WEPCO proposed to suspend its RED Program. The RED Program was intended to meet WEPCO's renewable resource commitments in the Final Decision in docket 5-CE-130 (PSC REF#: 86450). These commitments included spending an additional $6 million a year for ten years, subject to regulatory approval and cost recovery, to develop renewable energy technologies and resources. The Commission determines it is not appropriate to include funding of the RED Program in the revenue requirement. Since the early 2000's WEPCO has spent almost a billion dollars to support and permit over 350 MW of renewable energy resources. As such, WEPCO has more than met the intent of this program, and it is not reasonable to ask ratepayers to pay more for renewable resources at a time of excess capacity.

Commissioner Callisto dissents.

Energy for Tomorrow (EFT)/Green Pricing Program

WEPCO and Commission staff proposed to increase the EFT green pricing premium. The Commission finds it reasonable to increase these premiums as proposed.

Commissioner Callisto dissents.

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 45.0 to 50.0 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. Furthermore, an appropriate target level for WG's test-year average common equity measured on a financial basis is 47.5 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 case 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 was reasonable to impute $358,160,000 of debt equivalent associated with WEPCO's off-balance sheet obligations. Incorporating this estimate 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, 0.47 percent preferred stock, 39.16 percent long-term debt, 3.90 percent short-term debt, and 5.47 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 47.50 percent common equity, 33.17 percent long-term debt, and 19.33 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 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. WG may not pay 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 47.50 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, the applicant should wait until the end of the test year to pay additional dividends to the parent. Such 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 level.

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 cases. The ten-year forecast can be combined with other business risk information to assess capital structure needs and rate of return requirements.

Regulatory Capital Structure and Cost of Capital

As in the previous rate case docket, Commission staff deducted WEPCO's investment in common equity of 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 rate-making capital structure for the purpose of establishing just and reasonable rates for WEPCO for the test year consists of 52.09 percent common equity, 0.51 percent preferred stock, 43.10 percent long-term debt, and 4.30 percent short-term debt. Similarly, a reasonable utility rate-making capital structure for the purpose of establishing just and reasonable rates for WG for the test year consists of 46.75 percent common equity, 33.65 percent long-term debt, and 19.60 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 $255,633,000 and $170,290,000, respectively, of short-term debt. The interest rate associated with the 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 0.53 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 33 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 test-year long-term debt includes an issuance of 30-year debt aggregating $250,000,000 principal amount forecasted for issuance in 2012. In addition, the test year included an issuance of 30-year debt aggregating $350,000,000 principal amount forecasted for issuance in 2013. A reasonable estimate for the cost of the new indebtedness is 3.95 percent for the 2012 issuance and 4.55 percent for the 2013 issuance. The resulting embedded cost of long-term debt for WEPCO of 5.21 percent is reasonable for the test year.

Similarly, WG's test-year long-term debt includes a forecasted 2013 issuance of 30-year debt aggregating $150,000,000 principal amount. A reasonable estimate for the cost of the new indebtedness is 4.55 percent. A reasonable embedded cost of long-term debt for WG for the test year is 5.61 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-104, that a 10.40 percent return on utility common equity for WEPCO and a 10.50 percent return on utility equity for WG is reasonable. As rate of return on common equity was not an issue addressed in this proceeding, the Commission determines that this return on equity shall remain in place until addressed in a subsequent rate case proceeding. Using a 10.40 percent return on equity, 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	$3,101,124	52.09%	10.40%	5.42%
Preferred Stock	30,450	0.51%	3.95%	0.02%
Long-Term Debt	2,565,769	43.10%	5.21%	2.25%
Short-Term Debt	255,633	4.30%	0.53%	0.02%
Total Utility Capital	$5,952,976	100.00%		7.71%

The weighted cost of capital of 7.71 percent is reasonable for WEPCO for the test year. It generates an economic cost of capital of 11.34 percent and a pre-tax interest coverage ratio of 4.99 times, on the regulatory capital structure.

Using a 10.50 percent return on equity, 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	$406,101	46.75%	10.50%	4.91%
Long-Term Debt	292,308	33.65%	5.61%	1.89%
Short-Term Debt	170,290	19.60%	0.53%	0.10%
Total Utility Capital	$868,699	100.00%		6.90%

The weighted cost of capital of 6.90 percent is reasonable for WG for the test year. It generates an economic cost of capital of 10.19 percent and a pre-tax interest coverage ratio of 5.12 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 84.84 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 77.33 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 since on-going 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, the forecasted amount of construction activity, and consistent with the Commission's prior decision in docket 5-UR-104, the Commission finds it reasonable to allow electric operations to accrue Allowance for Funds Used During Construction on 100 percent of CWIP associated with two electric utility projects: the Oak Creek Air Quality Control System and the Rothschild renewable energy biomass project. 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				WG
	Electric	Natural Gas	VA Steam	MC Steam	Natural Gas
Weighted Cost of Capital	7.71%	7.71%	7.71%	7.71%	6.90%
Ratio of Average Net Investment Rate Base Plus CWIP to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	84.84	84.84%	84.84%	84.84%	77.33%
Adjusted Cost of Capital to Derive Percent Return Requirement Applicable to Average Net Investment Rate Base	9.09%	9.09%	9.09%	9.09%	8.92%
Adjustment to Return Requirement to Provide Current Return on CWIP	0.06%	0.06%	0.08%	0.09%	0.04%
Adjustment to Return Requirement to Provide Current Return on PTF Escrow, MISO Deferral, and MISO WUMS Deferral at short term debt of 0.53 percent	0.00%				
Required Rate of Return on Average Net Investment Rate Base	9.15%	9.15%	9.17%	9.18%	8.96%

Revenue Requirement

On the basis of the findings in this Final Decision, a $114,821,000 increase in WEPCO electric utility revenues, an $8,052,000 decrease in WE-GO utility revenues, a $1,256,000 increase in WEPCO's VA Steam utility revenues, an $1,040,000 increase in WEPCO's MC Steam utility revenues, and a $34,281,000 decrease in WG natural gas utility revenues, are reasonable for the purpose of determining reasonable and just rates for 2013 in this proceeding. In addition, on the basis of the findings in this Final Decision, a $73,442,000 increase in WEPCO electric utility revenues, a $1,332,000 increase in WEPCO's VA Steam utility revenues, and a $954,000 increase in WEPCO's MC Steam utility revenues, are reasonable for the purpose of determining reasonable and just rates for 2014 in this proceeding. These increases and decreases are computed as follows:

	WEPCO				WG
	Electric	Natural Gas	VA Steam	MC Steam	Natural Gas
Pro Forma Return on Average Net Investment Rate Base at Present Rates	6.29%	10.48%	3.87%	3.80%	12.06%
Required Return on Average Net Investment Rate Base	9.15%	9.15%	9.17%	9.18%	8.96%
Earnings Deficiency (Excess Earnings) as a Percent of Average Net Investment Rate Base	2.86%	(1.33%)	5.30%	5.38%	(3.10%)
Average Net Investment Rate Base (000's)	$3,928,415	$370,965	$29,201	$22,228	$664,799
Amount of Earnings Deficiency (Excess Earnings) on Average Net Investment Rate Base (000's)	$112,174	$(4,927)	$1,548	$1,196	$(20,587)
Revenue Deficiency (Excess Revenue) to Provide for Earnings Deficiency (Excess Earnings) Plus Federal and State Income Taxes (000's) before Adjustments	$187,086	$(8,217)	$2,582	$1,994	$(34,388)
Tax Asset & Liability Settlement Items	$(1,875)	$165	$6		107
Removal of Biomass and Solar Projects and Biomas PTC	$(7,475)				
2013 Revenue Deficiency (Excess Revenue) to Provide for Earnings Deficiency (Excess Earnings) Plus Federal and State Income Taxes after Adjustments (000's)	$177,736	$(8,052)	$2,588	$1,994	$(34,281)
2013 Treasury Grant Bill Credit	$(62,915)				
2013 Steam increases deferred to 2014			$(1,332)	$(954)	
Net 2013 Rate Increase (Decrease) After Electric Bill Credit and Steam Deferrals	$114,821	$(8,052)	$1,256	$1,040	$(34,281)
2014 Revenue Deficiency for Biomass Project	$27,984				
Incremental Treasury Grant Refunded in 2014[8]	$45,458				
Net 2014 Rate Increases	$73,442		$1,332	$954	

[8] The Wisconsin retail portion of the treasury grant benefit of $80,372,000 is split between a bill credit of $62,915,000 in 2013 and $17,457,000 in 2014. The 2014 incremental amount of $45,458,000 is due to a reduction to the 2013 bill credit of this amount to arrive at the 2014 bill credit ($62,915,000 - $45,458,000 = $17,457,000).

STEAM AND ELECTRIC RATES

Electric Cost-of-Service, Revenue Allocation and Rate Design

WEPCO submitted the results of six different COSS that allocated production plant in a variety of ways. WEPCO submitted a proposed revenue allocation and identified several reasons why its proposed revenue allocation did not match with the results of its COSS, including the mismatch between the allocators used to conduct cost studies and rate design billing elements and a desire for rate stability.

WIEG criticized the use of the equivalent peaker method preferred by WEPCO in several of its costs studies on the basis that WEPCO had not provided any support for the equivalent peaker method's underlying principle that a portion of the costs of production plants were incurred to achieve savings in fuel costs. WIEG recommended that the Commission approve a revenue allocation using the results of WEPCO's 4-CP cost study with 100 percent of production plant allocated on demand and WEPCO's allocation of distribution plant.

CUB argued that a greater share of production plant should be allocated on the basis of energy use than the amount which resulted from WEPCO's equivalent peaker method. CUB also disputed WEPCO's preference for the use of the 4-CP allocator for the demand-related portion of production costs and WEPCO's allocation of distribution costs. CUB proposed that all distribution costs, except services should be allocated using a demand allocator.

Commission staff expressed several concerns with WEPCO's cost studies including its reliance on the 4-CP allocator to allocate production costs in its preferred study and the use of the minimum system method and its split of single-phase and three-phase distribution in its allocation of distribution costs. Commission staff proposed an allocation of the revenue increase based upon a revenue allocation that WEPCO had submitted, scaled down proportionally to match Commission staff's proposed revenue requirement. In Commission staff's revenue allocation, the incremental fuel costs were allocated on the basis of class energy sales. Fuel costs were not included in WEPCO's revenue allocation.

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 COSS 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 2013 and 2014 shown in Appendix B are reasonable. The Commission finds that it is reasonable to allocate the difference between the fuel costs included in Commission staff's proposed revenue requirement and the fuel costs included in the 2013 revenue requirement in this Final Decision on the basis of class energy sales.

Electric Rate Design

The Commission finds that the rate design proposed by WEPCO is reasonable. In general, this rate design includes relatively greater increases in demand charges and lesser increases in energy charges for the commercial and industrial rate classes. The Commission finds that it is reasonable to increase monthly facilities charges about halfway between the increases proposed by Commission staff and WEPCO. It is not reasonable to increase the credits for non-firm service as proposed by WIEG.

Commissioner Calisto dissents on the significant increase for the monthly facilities charges and the higher increases for the demand charges than for the energy charges.

Residential Air Conditioner Direct Load Control Program

WEPCO has operated a direct load control program for residential air conditioners for a number of years. This program is known as "Energy Partners." WEPCO proposed to discontinue this program on the basis that it is no longer cost-effective. The Commission finds that it is reasonable for WEPCO to discontinue this program.

Commissioner Calisto dissents.

Rate and Rule Changes

The Commission finds that the electric rate and rule changes proposed by WEPCO are reasonable.

2005 Wisconsin Act 141 Costs in Base Rates

The electric portion of the company's Act 141 conservation costs included in the 2013 test-year electric revenue requirement is $36,876,810. This amount must be allocated differently to "large energy customers"[9] and to non-large customers due to a statutory limitation on how much the "large energy customers" can be billed for Act 141 costs. The Act 141 costs in base rates for the residential rate classes differs from the Act 141 cost in base rates for the commercial and industrial rate classes based on an allocation of the costs between the residential and non-residential classes and the statutory limitation on what the large customers can pay. Commission staff recommended that the appropriate allocation of the Act 141 costs should reflect the Focus on Energy spending for the entire state, which is 40 percent for residential classes and 60 percent for the non-residential classes. Such an allocation would be consistent

[9] Under Wis. Stat. § 196.374(1)(em), a "large energy customer" is defined as a customer whose facility consumes at least 1,000 kW of electricity per month or at least 10,000 dekatherms of natural gas per month and who is billed at least $60,000 in a month for electric and natural gas services. All accounts of a company that qualifies as a large energy customer are treated as a large energy customer for billing purposes.

with the allocation of Act 141 costs approved by the Commission for the other large investor-owned utilities. The Commission determines that Commission staff's proposal for the allocation of the Act 141 costs and the associated Act 141 rate factors for electric rates, which are shown in Appendix B, are reasonable.

WEPCO currently excludes the Act 141 revenues from its calculation of the revenue from sales of electricity. It escrows this revenue and includes it as "other revenue" in the overall revenue requirement, not in its calculation of class revenues. Commission staff proposed that the company provide additional information regarding the Act 141 costs and the billings of it large energy customers in its next rate case. The Commission determines that in WEPCO's next rate case, WEPCO must provide billing units and the associated revenue reflecting the Act 141 costs in base rates and the associated refunds given to its large energy customers for each customer class, and include this revenue in both the present and proposed class revenue calculations, rather than continue the company's current approach. This is consistent with the treatment of Act 141 revenues used by the other large investor-owned utilities.

Customer-Owned Generation

WEPCO proposed to transfer existing customers between its CGS2, CGS6, and CGS7 net metering tariffs so as to reorganize customers based on metering and generation type. As this change will not result in a bill impact for existing net metering customers, the Commission finds WEPCO's request to be reasonable.

The company proposed to close its CGS3 tariff to new customers due to current energy market conditions. The CGS3 tariff is for customers who can sell 300 kW or more of dispatchable customer-owned generation to the company. WEPCO anticipates that current market prices will make the likelihood very low that CGS3 generation will be dispatched. The Commission finds the company's request to close the CGS3 tariff to new customers reasonable.

WEPCO proposed closing the CGS6 tariff to new customers. As part of this proposal, WEPCO requested that the CGS6 tariff be closed to new customers retroactive to May 15, 2012, or alternatively, that the CGS6 tariff be eliminated entirely. WEPCO proposed a new CGS8 net metering tariff that would be available to new customers instead of CGS6. Closing the CGS6 tariff retroactive to May 12, 2012, would amount to retroactive rate-making, which this Commission has long held to be improper. Furthermore, WEPCO failed to provide sufficient justification as to why the Commission should consider retroactive closure. The Commission finds WEPCO's request to close the CGS6 tariff to new customers reasonable, but finds the company's request for retroactive closure, including the company's proposed alternative, to be unreasonable. The CGS6 tariff shall be closed to new customers effective on the same date as the rest of WEPCO's 2013 test-year rates.

WEPCO proposed a new CGS8 net metering tariff that would be available to new customers instead of CGS6. The CGS8 tariff proposed by WEPCO would maintain the 20 kW capacity limit of the CGS6 tariff, but would add a requirement that the customer's generation could, at most, be sized to match the customer's load requirements. The CGS8 tariff proposed by WEPCO differs from the company's existing CGS6 tariff with respect to the way in which net surplus generation is treated. Under CGS6, customers are credited at their applicable retail energy rate for any generation that is in net excess of the customer's monthly consumption. Under CGS8, the customer would be allowed to net their generation against their consumption annually, crediting customers for monthly net surplus generation at the retail energy rate, with the credit balance carried forward and offset against subsequent billing periods. Any remaining credit balance would be carried forward from month to month until May 1 of each year. At that point, any remaining credit balance would be forfeited by the customer. RENEW Wisconsin and Commission staff felt WEPCO's proposed CGS8 design was generally acceptable, but objected to the customers' forfeiture of annual net surplus generation. RENEW and Commission staff argued that customers should, at a minimum, be credited for annual net surplus generation at an avoided cost rate. WEPCO indicated that, should the customers be credited for annual net surplus generation, that avoided cost should be based on average LMP. RENEW argued that the annual net surplus credit rate should also reflect the utility's avoided cost of transmission.

WEPCO is obligated under the Public Utility Regulatory Policies Act (PURPA) to purchase power from Qualifying Facilities (QF) at avoided cost unless granted relief from the Federal Energy Regulatory Commission for purchase obligations. To date WEPCO has not been granted relief from its obligation to purchase power from QFs that fall within the eligibility criteria for CGS8. Additionally, as all customer-owned generation that meets the eligibility criteria for CGS8 service also meets the definitions of a QF, WEPCO is obligated to purchase power from CGS8 generators. In instances where the process of netting is used, such as in the case of the CGS8, it is only when the amount of energy generated exceeds the customer's consumption over the netting period that a sale to the utility occurs, and only in the net excess amount. Consistent with PURPA, this sale is made at an avoided cost rate. The Commission finds WEPCO's CGS8 tariff, modified so as to require that customers be paid for annual net surplus generation at an avoided cost rate, to be reasonable. The Commission finds it reasonable that the CGS8 avoided cost rate reflect average MISO LMP plus the utility's avoided cost of transmission.

Customers who take service under CGS8 are limited to 20 kW of aggregate capacity per location and may, at most, size their generating equipment so as to match the their load requirements at the same location. The Commission finds these availability conditions reasonable.

Commissioner Callisto dissents.

WEPCO requested that the Commission grant the company a waiver of Wis. Admin. Code § PSC 113.0406(5) ("Budget Billing") to net metering customers on tariffs CGS 2, 4, 6, 7, and 8. The company argued that budget billing obscures the customer's monthly use and generation, and in the absence of budget billing the customer can more readily see and understand the relationship between their generation and energy use, encouraging customer behavior that would maximize the return on the customer's investment in the renewable energy generator. Currently WEPCO has no customers with net metered customer owned generation receiving budget billing. The Commission finds the company's request for a waiver of Wis. Admin. Code § PSC 113.0406(5) for its CGS 2, 4, 6, 7, and 8 tariffs to be reasonable.

During the review of WEPCO's existing tariffs, Commission staff determined that exclusionary language in WEPCO's Fuel Cost Adjustment (FCA) sheet limiting the application of the FCA to CGS2, CGS4, CGS6, and CGS7 to instances where customers are net purchasers from the company may have inappropriately been added in a prior revision to the FCA. WEPCO indicated that it would voluntarily correct the conflicting language in WEPCO's FCA sheet and issue credits, including interest, to those customers that were not credited fuel cost adjustments, starting with bills from June 2006. The Commission finds WEPCO's proposed resolution to this issue to be reasonable.

Steam Revenue Allocation and Rate Design

The Commission finds that the steam revenue allocation and rate design proposed by Commission staff is reasonable. The Commission also finds that the changes to the extension allowances and to the steam rules proposed by WEPCO are reasonable.

NATURAL GAS RATES

Natural Gas Cost-of-Service Studies

WE-GO and WG prepared fully embedded natural gas COSS in this proceeding using the companies' proposed revenue requirements. Commission staff allocated the proposed rate decreases to the service rate classes based on the major drivers that lowered the companies' overall revenue requirements since their last rate case.

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

Revenue Recovery Adequacy of Service Class Rates

Overall, the rates authorized for WE-GO in Appendix D of this Final Decision will provide a 9.15 percent rate of return on the average gas net investment rate base. This represents a decrease of 4.74 percent in margin rates and a decrease of 1.92 percent in total natural gas sales revenues. The rates authorized in Appendix E of this Final Decision for WG will provide an

8.96 percent rate of return on the average gas net investment rate base. This represents a decrease of 12.40 percent in margin rates and a decrease of 5.49 percent in total natural gas sales revenues. Margin rates exclude natural gas costs.

Authorized rates as set forth in Appendices D and E are based on the cost of supplying natural gas service to the various service rate classes and other rate setting goals. Summaries of the rate impacts on a service rate class are shown in Appendices D and E for WE-GO and WG, respectively.

As shown in Appendices D and E, the authorized natural gas rates result in a range of decreases in the charges to the various service rate classes. To provide for historical continuity in WE-GO's and WG's rates, the Commission finds it reasonable to authorize service rates that move in the direction of the natural gas COSS results, with intent to make further adjustments in that direction in subsequent rate proceedings. The percentage rate decrease to any individual customer will not necessarily equal the overall percentage decrease to the associated service rate class, but will depend on the specific usage level of the customer.

Appendices D and E also show some typical natural gas bills for residential service, comparing existing rates with new rates, including the cost of natural gas.

Effective Date

The Commission finds it reasonable for the authorized electric and steam rate increases and all tariff provisions that restrict the terms of service to take effect January 1, 2013, provided that these rates and tariff provisions are filed with the Commission and placed in all offices and pay stations of the utilities by that date. If these rate increases and tariff provisions are not filed with the Commission and placed in all offices and pay stations by that date, it is reasonable to require that they take effect on the date they are filed with the Commission and placed in all offices and pay stations.

The Commission finds it reasonable for the authorized natural gas rate decreases and all tariff provisions that do not restrict the terms of service to take effect January 1, 2013. It is also reasonable to require that the utilities file these rate decreases and tariff provisions with the Commission and place them in all offices and pay stations of the utilities by that date.

Order

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

2. The authorized rate increases and tariff provisions that restrict the terms of service may take effect January 1, 2013, provided that the utility files these rates and tariff provisions with the Commission and places them in all of the utility's offices and pay stations by that date. If these rate increases and tariff provisions are not filed with the Commission and placed in all offices and pay stations by that date, they take effect on the date they are filed with the Commission and placed in all offices and pay stations.

3. WEPCO may revise its existing rates and tariff provisions for electric and steam utility service, substituting the rate increases and tariff provisions that restrict the terms of service, as shown in Appendix B and C. 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, 2013. The utility shall file these rate decreases and tariff provisions with the Commission and place them in all offices and pay stations of the utility by that date.

5. By January 1, 2013, WEPCO and WG shall revise their existing rates and tariff provisions for natural gas utility service, substituting the rate decreases and tariff provisions that expand the terms of service, as shown in Appendices D and E. These changes shall be in effect until the Commission issues an order establishing new rates and tariff provisions.

6. WEPCO and WG are authorized to substitute, for their existing rates and rules for electric, natural gas, and steam service, the rate and rule changes contained in Appendices B, C, D, and E. These rates and rules shall be in effect until the issuance of an order by the Commission establishing new rates and rules.

7. The applicants shall prepare bill inserts that properly identify the rates authorized in this Final Decision. The applicants shall distribute the inserts to customers no later than the first billing containing the rates authorized in this Final Decision and shall file copies of these inserts with the Commission before it distributes the inserts to customers.

8. The applicants shall file tariffs consistent with this Final Decision.

9. The electric fuel costs in Appendix F shall be used for monitoring of WEPCO's 2013 fuel costs, pursuant to Wis. Admin. Code §PSC 116.06(3).

10. The $24,345,473 in fuel flexibility cost shall be included in the 105 percent Approved Amount cost over-run limit calculation and recovery of this amount shall be deferred until a future rate case proceeding wherein the prudence of costs can be determined.

11. WEPCO shall be allowed to recover through the ERGS lease payment calculation no more than the $109,551,303 allowed under the 105 percent of the Approved Amount cost over-run limit.

12. WEPCO shall be allowed to recover through the ERGS lease payment calculation $56,481,061 in *force majeure* cost over-runs.

13. The cost to WEPCO associated with ERGS cost items not yet settled, such as the low-pressure turbine issue, the punch list items, and the final cost review items, shall be deferred until a future rate case proceeding.

14. The annual cost to WEPCO of compliance with the WPDES settlement may not be included in the electric rates for 2013 and 2014.

15. WEPCO may defer the $4,956,127 in legal expense associated with the WPDES settlement agreement, for review in a future rate case proceeding.

16. WEPCO may not recover the cost associated with the 5 MW of solar generation identified in this docket.

17. WEPCO shall reinstate a new transmission escrow account on a temporary basis for non-labor transmission O&M expenses, and WEPCO shall record a transmission expense of $250.7 million for 2013 and 2014 on a Wisconsin retail basis or until the Commission authorizes a different transmission expense to be recorded.

18. WEPCO shall accrue carrying costs on its new, reinstated, temporary transmission escrow on a net-of-tax basis, calculated at the authorized short-term debt rate.

19. WEPCO shall amortize $1,557,000 of escrowed uncollectible accounts expense for WEPCO's electric utility on a Wisconsin retail basis, which is a four-year amortization of its under-collected balance, for 2013 and 2014 or until the Commission authorizes a different amortization expense to be recorded.

20. WEPCO shall amortize a negative $2,287,000 of escrowed uncollectible accounts expense for WEPCO's gas utility, which is a four-year amortization of its over-collected balance, for 2013 and 2014 or until the Commission authorizes a different amortization expense to be recorded.

21. WG shall amortize a negative $14,956,000 of escrowed uncollectible accounts expense for WG, which is a four year amortization of its over-collected balance, for 2013 and 2014 or until the Commission authorizes a different amortization expense to be recorded.

22. WEPCO shall reduce the balance of its PTF escrow account at the beginning of the test year by $618,000 to remove bonuses and incentives charged in error to the escrow.

23. WEPCO shall reduce the deferred balances associated with Section 199 deferred carrying costs and deferred coal legal costs to zero at the beginning of the test year.

24. All authorized amortizations shall begin as of the effective date of this Final Decision.

25. The RLIP is approved as a permanent program.

26. We Energies shall work with Commission staff to ensure the RLIP maintains a positive cost-benefit ratio.

27. Load management expenditures shall be funded through non-escrow O&M.

28. The Agriculture Services program shall be funded through non-escrow O&M.

29. Funding for the RED Program may not be recovered from ratepayers. WEPCO may discontinue the RED Program.

30. WEPCO electric shall record $45,848,000 of conservation escrow expense, which consists of $33,108,000 of estimated expenditures and $12,740,000 of amortization of

underspent amounts. For WE-GO, the company shall record $14,772,000 of expense, which consists of $10,436,000 of estimated expenditures and $4,336,000 of amortization of underspent amounts. For WG, the company should record $14,304,000 of expense, which consists of $12,745,000 of estimated expenditures and $1,559,000 of amortization of underspent amounts.

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

32. WEPCO shall credit CGS8 customers for any annual net-surplus generation at an avoided cost rate based on average LMP plus the company's avoided cost of transmission.

33. Customers who take service under CGS8 are limited to 20kW of aggregate capacity per location and may, at most, size their generating equipment so as to match their load requirements at the same location.

34. In future rate case proceedings, WEPCO shall model its portion of the ERGS units as economic in the MISO energy market during the non-summer months of the test year.

35. Jurisdiction is retained.

Dissent and Concurrence

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

Dated at Madison, Wisconsin, this 21st day of December, 2012.

By the Commission:

for

Sandra J. Paske
Secretary to the Commission

SJP:CCS:cmk:DL:00605947

See attached Notice of Rights

PUBLIC SERVICE COMMISSION OF WISCONSIN
610 North Whitney Way
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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 mailing of this decision, as provided in Wis. Stat. § 227.49. The mailing date is shown on the first page. If there is no date on the first page, the date of mailing is shown immediately above the signature line. The 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 mailing 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 mailing 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 mailed its original decision.[10] 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: December 17, 2008

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

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-106

DISSENT AND CONCURRENCE
OF COMMISSIONER ERIC CALLISTO

While I generally concur in the *Final Decision*, I write separately to explain my dissenting position on a number of issues.

I also write separately here in concurrence, as I did in the recent rate decisions for Superior Water, Light and Power Company and Madison Gas and Electric Company, to highlight a recurring inequity associated with how Wisconsin law treats certain large energy customer contributions to Focus on Energy, the state's utility-funded energy efficiency and renewable resource program.

Late Adjustments (FTR Offset; 2013 Fuel Costs; Coal Sales Estimate; Gross Receipts Tax)

The utility proposed late, upward adjustments to its revenue requirement relating to: (i) the appropriate financial transmission rights (FTR) revenue offset associated with SPS, P4-Zion Line 2 and ATC line rating reductions; (ii) 2013 fuel costs associated with the P4-Zion Line 2; (iii) coal sales revenue estimates; and (iv) the forecast of gross receipts tax expense. For each issue, the upward adjustment was proposed relatively late in the rate proceeding, after the Commission staff audit was completed. Together, these adjustments add more than $14 million to the utility's revenue requirement.

The Commission has a long-standing practice of disallowing revenue requirement adjustments that are submitted after the staff audit is complete. Late revenue adjustments are difficult for Commission staff and intervening groups to adequately evaluate and are thus more likely to be insufficiently developed by the time of the Commission's decision. I would have supported Commission staff's position on each of these issues, disallowing about $14 million worth of increases.

Valley Power Plant – Cost Allocation

The Valley Power Plant runs almost entirely for the benefit of steam customers. At 280 megawatts, the plant was originally built for electricity, but its value on the electric market has markedly diminished since it first began operation more than 40 years ago. Valley has a high heat rate, it is more expensive to run every year, and it is routinely out of the money in the MISO energy market. Indeed, Valley's performance in the MISO market is telling: if WEPCO did not designate Valley as a "must-run" and instead allowed the energy market to decide when it was needed, it would only be chosen five percent of the time compared to how often it now runs. The fact is that Valley is primarily a steam plant that benefits about 450 steam customers.[11] The costs of running it, however, will continue to be spread across the utility's electric ratepayers. Today's *Final Decision* preserves about a $5 million annual cross-subsidy.

Much has been made of the impact that eliminating the Valley subsidy would have had on a relatively small number of steam customers in Milwaukee. Those are legitimate concerns that I share. Whenever one group of utility customers is being relieved of a subsidy obligation, the group that has been benefiting from it will inevitably experience a rate impact. And it is the job of the Commission to mitigate those impacts, often by gradually phasing in the new cost allocation in rates. In this case, I would have supported a reallocation of $1 million of Valley fuel costs to the steam customers for 2013, and then a $500,000 additive increase in 2014, for a total of about a six percent steam rate increase over two years. That's not as far as the Citizens

[11] WEPCO attempted to argue that the unit is necessary for electric reliability, but was unable to produce a witness to credibly substantiate that claim. Notably, MISO did not testify, and WEPCO does not let MISO decide if the Valley unit must run for electric reliability.

Utility Board advocated, but it would be an important step in beginning to undo what has become a fairly obvious cross-subsidy of steam service.

O&M Deviations from the Commission Staff Audit

The *Final Decision* includes nearly $12 million more in forecasted O&M expenses than what Commission staff arrived at in its audit of the revenue requirement. The *Final Decision*'s deviations from staff on O&M relate to: (i) non-labor electric distribution expenses; (ii) employee medical benefit expenses; (iii) employee dental benefit expenses; and (iv) employee post-retirement expenses other than pension benefits. For each issue, Commission staff's adjustment is based on what the utility's actual expenses in these areas have been over the most recent three-year period versus what the utility requested from the Commission in previous rate applications. The Commission staff audit simply attempts to account for the well-documented history of overstating various forecasted O&M expenses. I would have accepted Commission staff's position on each of these issues, disallowing about $12 million in increases.

WPDES Settlement

The Commission's determination that the utility's legal expenses associated with the Wisconsin Pollutant Discharge Elimination System (WPDES) settlement should be deferred for possible recovery, but that the costs associated with complying with the settlement are not recoverable, is not supportable. The 2014 costs associated with the five megawatt solar project, and the 2013 and 2014 annual payments under the WPDES settlement devoted to Lake Michigan water quality, are fair and reasonable costs that should be approved for recovery.[12]

[12] No party in this proceeding has challenged the prudency or reasonableness of the annual payments required under the WPDES settlement.

It is perhaps difficult now to recall the rationale for the WPDES settlement, now more than four years old. It is a task made even more difficult by the near absence of any discussion of the settlement in the record in this docket or an explanatory justification for the ongoing annual Lake Michigan payments or the contemplated five megawatt solar project. In contrast, the utility explained at great length in docket 5-UR-114 the reasons for the settlement, specifically entering testimony about the company's qualitative analysis showing why settling the WPDES litigation was in the best financial interests of its customers.[13] It is worth remembering that if the lawsuit had not been settled, the company was facing a financial risk of between $815 million and $1.3 billion in net present value cooling tower retrofit costs.[14] No party in that docket questioned the company's cost-benefit analysis regarding proceeding with settlement versus taking on the additional risk of continued WPDES litigation.

It is not fair or appropriate to second guess that settlement now. The costs it entailed – the solar project, the annual Lake Michigan payments, a biomass generation project (which the Commission approved in 2011) – made sense at the time in the context of what the company fairly assumed were real and substantial financial risks of the environmental litigation. We have no reason to challenge the company's underlying analysis at this juncture – indeed no one has – other than the fact that the bill has come due. It is unfortunate the company did not do a better job articulating *in this case* the rationale it so vigorously defended just three years before this same body.

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[13] *See generally Applicants' Initial Post-Hearing Brief* in docket 5-UR-104 at pages 15 – 20 (PSC REF #122036).
[14] *See id.*

Renewable Energy Development Program

WEPCO should continue to fund its Renewable Energy Development Program, at least at a reduced level. The program is the result of a ten-year old agreement between the utility and renewable energy advocates regarding ongoing funding of smaller-scale renewable energy technologies, at $6 million per year for ten years. The utility originally agreed to the program apparently as part of its support gathering effort for the then-planned Power the Future (PTF) projects. WEPCO made clear its intentions for the program in its CPCN filing for PTF, and the Commission acknowledged the parties' plans for the program in its decision approving the PTF CPCN. The utility received the benefit of the bargain (certain parties' lack of opposition to PTF), and the Commission took the agreement, and its attendant costs, into account in making its decision. It is only fair that the program be allowed to reach completion. In recognition of what the utility has done in support of renewable energy, I would have supported $2 million for this program, rather than $6 million.

Electric Rate Design (Facilities Charge; Demand Charge)

Increasing WEPCO's facilities charge is unnecessary. The Commission's decision to increase the facilities charge by 20 percent is consistent with its *Final Decision* in docket 3270-UR-118, this year's MGE rate case. I oppose the WEPCO facilities charge increase for the same reasons I opposed the customer charge increases for MGE: additional financial risk reduction for WEPCO is simply not justified, increasing fixed charges mutes customer price signals and frustrates conservation goals, and they are regressive, hitting the smallest, lowest use customers the hardest.[15]

[15] *See Final Decision* in docket 3270-UR-118 (Commissioner Callisto, concurring and dissenting in part).

I also do not support ordering demand charge increases by a substantially greater percentage than the energy charge increases. In so doing, the *Final Decision* ensures a relatively wide bill impact disparity for WEPCO's large customers within the same classes. Putting more of the increase in the demand charge hits the lower load-factor customers harder, and will cause for some low load-factor customers a bill impact that is double the increase compared to high-load factor customers within the same customer class.

Energy for Tomorrow Green Pricing

The *Final Decision* includes a 74 percent rate increase for green pricing customers. That's too steep of an increase, too fast. While I agree that green pricing rates should better reflect the full cost of the energy procured to support them, I believe responsible utility regulation embodies a preference for gradualism in modifying rates. A 74 percent increase, all at once, is not gradual. I recently pointed out how this Commission is willing to adopt gradual rate changes for some customers (e.g., large energy users on WP&L's parallel generation tariff), but not for green pricing customers.[16] That same observation applies here. If this Commission was truly concerned about rate shock – for all utility customers – it would have adopted a phased-in approach for WEPCO's green pricing program and allowed the increase to gradually progress over at least a few years. I proposed a three-year progression to get to full cost pricing.

CGS8 Net Metering Tariff

Requiring that customer-owned renewable generation be limited in size to match the customer's annual load requirements in unnecessary. The tariff already limits the buy-back price to avoided cost, a rate that will almost certainly be substantially less than the cost of the customer's renewable generation. As such, the avoided cost buy-back should act as a clear

[16] *See id.* (Commissioner Callisto, concurring and dissenting in part) at page 3.

disincentive for oversizing customer-owned generation equipment and protects against the possibility of customer windfall. For similar reasons, I find unnecessary the 20 kilowatt capacity limit. The Commission accepts a 100 kilowatt capacity limit for similar tariffs offered by other Wisconsin investor-owned utilities, and we should allow the same for WEPCO.

Act 141 Large Energy Customer Contributions

I write separately here in concurrence, as I did in the recent rate decisions for Superior Water, Light and Power Company and Madison Gas and Electric Company, to highlight a recurring inequity associated with how Wisconsin law treats certain large energy customer contributions to Focus on Energy, the state's utility-funded energy efficiency and renewable resource program.[17]

Energy efficiency programs in Wisconsin are governed by 2005 Wisconsin Act 141 ("Act 141"). Among other things, Act 141 requires the state's utilities to collectively establish and fund a statewide energy efficiency program ("Focus on Energy"), establishes priorities for the expenditure of those funds, and creates a system of joint oversight, involving the state's utilities, the Commission, and the third party contractor that administers the program. *See generally* Wis. Stat. § 196.374.

Focus on Energy is funded through ratepayer dollars, at an amount equal to 1.2 percent of utility revenues. Wis. Stats. §§ 196.374(3)(b)2. and (5)a. However, each individual ratepayer's contribution to Focus on Energy is not equal to 1.2 percent of their utility bills. While the Commission has determined that the rate classes should generally pay an amount equal to the amount of Focus on Energy incentives distributed to their class, a limited number of large

[17] *See Final Decisions* in dockets 5820-UR-113 (Commissioner Callisto, concurring) and 3270-UR-118 (Commissioner Callisto, concurring and dissenting in part).

customers pay much less. That disparity and the subsidy that it necessitates is the result of a section of Act 141 which specifically directs that certain "Large Energy Customers"[18] ("LECs") pay into Focus on Energy the amount they paid towards similar programs in 2005, rather than the amount determined by the Commission. Wis. Stat. § 196.374(5)(b)1. and 2005 Wisconsin Act 141, § 102(8)(c). There are currently 869 LECs in Wisconsin, and specifically 269 LECs in the service territory of WE Energies.

Most LECs pay less into Focus on Energy than they otherwise would in the absence of the statutory exemption. Some LECs pay no money into Focus on Energy because they were paying no money to similar programs in 2005. Regardless of how much they pay into the program, all LECs remain eligible to receive the benefits of Focus on Energy, at an undiminished level.

In the WE Energies rate case we approve today, LECs are paying about $14 million less than they would if all customers were required to pay proportionally equal amounts.[19] The amount last year was about the same.[20] Accounting for the state's six largest utilities, in 2010, the most recent year for which full data is available, LECs paid $16.2 million less than they would have if the statutory exemption didn't exist.[21] Because the utilities are required to fund the program at 1.2 percent of revenues, that missing LEC money must come from somewhere

[18] A "large energy customer" is a customer that has a demand of at least 1,000 kilowatts of electricity per month or of at least 10,000 decatherms of natural gas per month and, in a month, is billed at least $60,000 for electric service, natural gas service, or both. Wis. Stat. § 196.374(1)(em).

[19] This includes both gas and electric large energy customers of the utility.

[20] On average, the WE Energies LECs enjoy a 77% discount on the electric rate they pay for Act 141 programs when compared against proportionally equal amounts. The rate for all of the non-residential customers to pay for Act 141 programs would have been approximately $0.00136/kWh, if not for this legislation. Under the approved rates, LECs will pay $0.00031/kWh for Act 141 program contributions, while non-LECs will pay $0.00152/kWh. Under present rates, the disparity is $0.00039/kWh vs. $0.00170/kWh.

[21] *See* Wisconsin Legislative Audit Bureau Report 11-13, Evaluation of the Focus on Energy Program, pp. 21 – 22 (December 2011).

else, and indeed it does. Those costs are allocated to other non-residential customers. In this case, all of WE Energies' commercial, industrial, and lighting customers that do not meet the LEC threshold are required to pick up these extra amounts, and essentially subsidize the rate break enjoyed by 269 LECs.

And while, generally, under-collection from LECs is the result of the Act 141 exemption, some LECs in Wisconsin have actually paid more than their proportional share of utility revenues because of the operation of the exemption.[22] Either way, the result is inequitable.

Furthermore, the LEC exemption creates perverse incentives that may not be readily apparent. If a LEC is close to the cutoff line for retaining this designation (i.e., its monthly energy use and/or bill amounts are dropping close to the statutory thresholds), it may not choose to pursue energy efficiency because the energy savings may have a value less than the likely "full" Focus on Energy payment it would be required to make as a non-LEC. Conversely, those customers falling just short of the LEC threshold may have an incentive to use more energy – even when they don't need it – if they believe getting the LEC designation (and the resulting lower Focus on Energy payment) will be more valuable than the energy costs incurred to get to the threshold. It cannot be that Act 141 was intended to create economic incentives for inefficient and wasteful energy usage, which is precisely what the LEC exemption promotes.

Freezing the LEC contributions to Focus on Energy at 2005 levels was meant to be temporary.[23] Act 141 required the Commission, by no later than the end of 2008, to provide the Legislature with a recommendation for equitable cost recovery from all rate classes. Wis. Stat. § 196.374(5)(bm)1. While the Commission did submit a proposal recommending a

[22] *See id.* at p. 22, Table 7 (illustrating how Wisconsin Power & Light's LECs pay $616,000 more that they would without Act 141's exemption).
[23] *See id.* at p. 20 ("Legislative documents describe [the Act 141 LEC exemption] as a 'first step' . . .).

3-year phase-in to proportionally equal funding for LECs, no legislative action was undertaken.[24] As a result, most LECs continue to enjoy proportionally lower contributions to Focus on Energy than other customers in their own rate classes, and in other non-residential customer classes.[25] And those rate breaks for the LECs continue to be subsidized by other commercial and industrial customers.

Not every inequity created by the statutes warrants the Commission's attention. However, where the Legislature empowered the Commission to make a recommendation to resolve an acknowledged disparity in the initial statutory scheme, where that recommendation was not acted on, and where the inequity persists, it is reasonable to make a run at it again. I encourage the Legislature to resolve this issue in the next legislative session.

[24] The Commission's 2008 recommendation can be found at PSC REF #106987.

[25] LEC contributions to Focus on Energy are subject to annual adjustments equal to the lesser of the percentage increase in the host utility's operating revenues in the preceding year or the increase in the consumer price index. Wis. Stat. § 196.374(5)(bm)2.

SERVICE LIST

In order to comply with Wis. Stat. § 227.47, the following parties who appeared before the agency are considered parties for purposes of review under Wis. Stat. § 227.53.

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Wisconsin Electric Power Company
Electric Revenue Summary
for Test Year ending December 31, 2013 & for 2014

Rate Schedules & Customer Classes	Revenue in TY2013 with Present Rates	Revenue in 2013 with Authorized Rates	Change 2013 Over Current	Revenue in 2014 with Authorized Rates	Change 2014 Over 2013	Change 2014 Over Current
Rg1	$1,057,910,681	$1,117,456,631	5.63%	$1,142,783,993	2.27%	8.02%
Fg1	$26,838,920	$28,166,883	4.95%	$28,836,529	2.38%	7.44%
Rg2	$39,721,310	$41,576,296	4.67%	$42,698,308	2.70%	7.49%
Rg3	$551,011	$581,065	5.45%	$598,110	2.93%	8.55%
Total Residential & Farm	$1,125,021,922	$1,187,780,875	5.58%	$1,214,916,940	2.28%	7.99%
Cg1	$228,159,939	$239,690,849	5.05%	$245,359,060	2.36%	7.54%
Cg6	$11,754,624	$12,309,530	4.72%	$12,640,380	2.69%	7.54%
TSS	$672,514	$700,846	4.21%	$717,959	2.44%	6.76%
Total Small General Secondary	$240,587,077	$252,701,225	5.04%	$258,717,399	2.38%	7.54%
Total Small Customer Class	**$1,365,608,999**	**$1,440,482,100**	**5.48%**	**$1,473,634,339**	**2.30%**	**7.91%**
Cg2 (Medium Customer Class)	**$191,162,285**	**$194,945,903**	**1.98%**	**$200,022,495**	**2.60%**	**4.63%**
Cg3	$558,569,168	$573,942,737	2.75%	$589,468,502	2.71%	5.53%
Cg3A	$1,446,070	$1,485,701	2.74%	$1,526,891	2.77%	5.59%
Cg3C	$4,864,215	$4,975,827	2.29%	$5,121,952	2.94%	5.30%
Cg3S	$528,296	$542,709	2.73%	$557,547	2.73%	5.54%
Total Large General Secondary	$565,407,749	$580,946,974	2.75%	$596,674,892	2.71%	5.53%
Total General Secondary	$997,157,111	$1,028,594,102	3.15%	$1,055,414,786	2.61%	5.84%
Cp1 Low	$24,576,251	$25,378,070	3.26%	$26,116,887	2.91%	6.27%
Cp1 Medium	$461,136,306	$475,742,022	3.17%	$489,929,615	2.98%	6.24%
Cp1 High	$5,311,961	$5,492,577	3.40%	$5,660,352	3.05%	6.56%
Cp3 Medium	$47,746,191	$49,677,338	4.04%	$51,194,964	3.05%	7.22%
Cp3A Low	$672,287	$695,900	3.51%	$716,633	2.98%	6.60%
Cp3A Medium	$7,500,462	$7,771,858	3.62%	$8,006,873	3.02%	6.75%
Cp3S Medium	$5,865,348	$6,077,081	3.61%	$6,260,519	3.02%	6.74%
CpFN Medium	$26,614,574	$27,548,539	3.51%	$28,528,467	3.56%	7.19%
CpFN High	$28,266,425	$29,026,484	2.69%	$30,154,496	3.89%	6.68%
CST High	$3,421,992	$3,421,992	0.00%	$3,421,992	0.00%	0.00%
RTMP	$4,814,504	$4,814,504	0.00%	$4,814,504	0.00%	0.00%
Total General Primary	$615,926,301	$635,646,365	3.20%	$654,805,302	3.01%	6.31%
Total Large Customer Class	**$1,181,334,050**	**$1,216,593,339**	**2.98%**	**$1,251,480,194**	**2.87%**	**5.94%**
Gl1	$6,455,244	$6,689,383	3.63%	$6,712,830	0.35%	3.99%
St1	$5,027,571	$5,271,766	4.86%	$5,463,031	3.63%	8.66%
Cg6	$670,708	$691,925	3.16%	$715,190	3.36%	6.63%
Al1	$605,874	$625,806	3.29%	$628,690	0.46%	3.77%
Ms1	$79,821	$80,914	1.37%	$81,186	0.34%	1.71%
Ms2	$2,302,612	$2,445,376	6.20%	$2,484,238	1.59%	7.89%
Ms3	$10,012,582	$10,131,221	1.18%	$10,164,300	0.33%	1.52%
Ms4	$3,836,931	$3,959,016	3.18%	$3,972,152	0.33%	3.52%
Mg1	$4,800	$4,800	0.00%	$4,800	0.00%	0.00%
Total Street Lighting & Other	**$28,996,143**	**$29,900,207**	**3.12%**	**$30,226,417**	**1.09%**	**4.24%**
Total Wisconsin Retail	**$2,767,101,477**	**$2,881,921,549**	**4.15%**	**$2,955,363,445**	**2.55%**	**6.80%**
Increases (for each year)		**$114,820,072**		**$73,441,896**		

Wisconsin Electric Power Company
Present and Authorized Electric Rates

Rate Schedules / Rate Descriptions	Present Rates	Authorized Rates in 2013	Authorized Rates in 2014	per Unit
Rg1 -- Residential Service				
Facilities Charge - Single Phase	$0.25000	$0.30000	$0.30000	per Day
Facilities Charge - Three Phase	$0.50000	$0.60000	$0.60000	per Day
Extra Meter Charge	$0.04665	$0.04665	$0.04665	per Day
Energy Charge - Base	$0.12611	$0.13816	$0.13945	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00362	$0.00000	$0.00000	per kWh
Rg2 -- Residential Service TOU				
Facilities Charge - Single Phase	$0.25000	$0.30000	$0.30000	per Day
Facilities Charge - Three Phase	$0.50000	$0.60000	$0.60000	per Day
Extra Meter Charge	$0.04665	$0.04665	$0.04665	per Day
On-Peak Energy Charge - Base Level 1	$0.18881	$0.20653	$0.20892	per kWh
On-Peak Energy Charge - Base Level 2	$0.24915	$0.27284	$0.27585	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00625	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base Level 1	$0.08578	$0.09403	$0.09491	per kWh
Off-Peak Energy Charge - Base Level 2	$0.04792	$0.05253	$0.05303	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00192	$0.00000	$0.00000	per kWh
Rg3 -- Residential Service Experimental TOU				
Facilities Charge - Single Phase	$0.25000	$0.30000	$0.30000	per Day
Facilities Charge - Three Phase	$0.50000	$0.60000	$0.60000	per Day
Extra Meter Charge	$0.04665	$0.04665	$0.04665	per Day
On-Peak Energy Charge - Base Summer	$0.28668	$0.38244	$0.38602	per kWh
On-Peak Energy Charge - Base Non Summer	$0.24915	$0.27284	$0.27585	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00625	$0.00000	$0.00000	per kWh
Mid-Peak Energy Charge - Base Summer	$0.24915	$0.27284	$0.27585	per kWh
Mid-Peak Energy Charge - Base Non Summer	$0.18881	$0.20653	$0.20892	per kWh
Mid-Peak Energy Charge - Fuel Cost Adjustment	$0.00625	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base Annual	$0.04792	$0.05253	$0.05303	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00192	$0.00000	$0.00000	per kWh
CPP - Residential & Small Commercial Critical Peak Pricing				
Facilities Charge - Single Phase	$0.25000	$0.30000	NA	per Day
Facilities Charge - Three Phase	$0.50000	$0.60000	NA	per Day
Extra Meter Charge	$0.04665	$0.04665	NA	per Day
Critical-Peak Energy Charge - Base	$0.88000	$0.88000	NA	per kWh
Non-Critical On-Peak Energy Charge - Base Annual	$0.24915	$0.27284	NA	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00625	$0.00000	NA	per kWh
Mid-Peak Energy Charge - Base Annual	$0.18881	$0.20653	NA	per kWh
Mid-Peak Energy Charge - Fuel Cost Adjustment	$0.00625	$0.00000	NA	per kWh
Off-Peak Energy Charge - Base Annual	$0.04792	$0.05253	NA	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00192	$0.00000	NA	per kWh
Fg1 -- Farm Service				
Facilities Charge - Single Phase	$0.25000	$0.30000	$0.30000	per Day
Facilities Charge - Three Phase	$0.50000	$0.60000	$0.60000	per Day
Extra Meter Charge	$0.04665	$0.04665	$0.04665	per Day
Energy Charge - Base	$0.12611	$0.13816	$0.13945	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00362	$0.00000	$0.00000	per kWh
Cg1 -- General Secondary Service				
Facilities Charge - Single Phase	$0.25000	$0.30000	$0.30000	per Day
Facilities Charge - Three Phase	$0.50000	$0.60000	$0.60000	per Day
Extra Meter Charge	$0.04665	$0.04665	$0.04665	per Day
Energy Charge - Base	$0.12611	$0.13816	$0.13945	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00362	$0.00000	$0.00000	per kWh

Wisconsin Electric Power Company
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Rate Schedules / Rate Descriptions	Present Rates	Authorized Rates in 2013	Authorized Rates in 2014	per Unit
Cg2 -- General Secondary Service - Demand				
Facilities Charge	$1.52877	$1.66000	$1.66000	per Day
Extra Meter Charge	$0.13151	$0.13151	$0.13151	per Day
On-Peak Energy Charge - Base	$0.11402	$0.12322	$0.12421	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00625	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.08777	$0.09091	$0.09169	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00192	$0.00000	$0.00000	per kWh
Regular On-Peak Demand Charge - Base	$5.677	$6.583	$6.761	per kW
Regular On-Peak Demand Charge - Fuel Cost Adjustment	$0.000	$0.000	$0.000	per kW
Low Hours of Use (HOU) Adjustment	$0.03406	$0.03950	$0.04128	per kW per HOU less than 100
Cg3 -- General Secondary Service - Demand/TOU				
Facilities Charge	$1.52877	$1.66000	$1.66000	per Day
Extra Meter Charge	$0.13151	$0.13151	$0.13151	per Day
On-Peak Energy Charge - Base	$0.07686	$0.08343	$0.08419	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00618	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.05600	$0.05822	$0.05875	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00190	$0.00000	$0.00000	per kWh
Regular On-Peak Demand Charge - Base	$11.354	$13.166	$13.385	per kW
Regular On-Peak Demand Charge - Fuel Cost Adjustment	$0.000	$0.000	$0.000	per kW
Low Hours of Use (HOU) Adjustment	$0.06812	$0.07899	$0.08119	per kW per HOU less than 100
Customer Demand Charge	$1.757	$1.800	$1.800	per kW
Cg3A -- Gen. Sec. - Energy Coop. Curtailable				
Facilities Charge	$3.41918	$3.50000	NA	per Day
Extra Meter Charge	$0.13151	$0.13151	NA	per Day
On-Peak Energy Charge - Base	$0.07686	$0.08343	NA	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00618	$0.00000	NA	per kWh
Off-Peak Energy Charge - Base	$0.05600	$0.05822	NA	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00190	$0.00000	NA	per kWh
Regular On-Peak Demand Charge - Base	$11.354	$13.166	NA	per kW
Regular On-Peak Demand Charge - Fuel Cost Adjustment	$0.000	$0.000	NA	per kW
Low Hours of Use (HOU) Adjustment	$0.06812	$0.07899	NA	per kW per HOU less than 100
Customer Demand Charge	$1.757	$1.800	NA	per kW
Curtailable Credit	$2.000	$2.000	NA	per kW
Cg3C -- Gen. Sec. - Experimental Curtailable				
Facilities Charge	$3.41918	$3.50000	$3.50000	per Day
Extra Meter Charge	$0.13151	$0.13151	$0.13151	per Day
On-Peak Energy Charge - Base	$0.07686	$0.08343	$0.08419	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00618	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.05600	$0.05822	$0.05875	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00190	$0.00000	$0.00000	per kWh
Regular On-Peak Demand Charge - Base	$11.354	$13.166	$13.385	per kW
Regular On-Peak Demand Charge - Fuel Cost Adjustment	$0.000	$0.000	$0.000	per kW
Low Hours of Use (HOU) Adjustment	$0.06812	$0.07899	$0.08119	per kW per HOU less than 100
Customer Demand Charge	$1.757	$1.800	$1.800	per kW
Curtailable Credit	$0.02080	$0.02080	$0.02080	per kW per On Peak HOU
Cg3S -- Gen. Sec. - Seasonal Curtailable				
Facilities Charge	$3.41918	$3.50000	$3.50000	per Day
Extra Meter Charge	$0.13151	$0.13151	$0.13151	per Day
On-Peak Energy Charge - Base	$0.07686	$0.08343	$0.08419	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00618	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.05600	$0.05822	$0.05875	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00190	$0.00000	$0.00000	per kWh
Regular On-Peak Demand Charge - Base	$11.354	$13.166	$13.385	per kW
Regular On-Peak Demand Charge - Fuel Cost Adjustment	$0.000	$0.000	$0.000	per kW
Low Hours of Use (HOU) Adjustment	$0.06812	$0.07899	$0.08119	per kW per HOU less than 100
Customer Demand Charge	$1.757	$1.800	$1.800	per kW
Curtailable Credit	$2.00000	$2.00000	$2.00000	per kW per On Peak HOU

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Cg6 -- General Secondary Service - TOU				
Facilities Charge - Single Phase	$0.25000	$0.30000	$0.30000	per Day
Facilities Charge - Three Phase	$0.50000	$0.60000	$0.60000	per Day
Extra Meter Charge	$0.04665	$0.04665	$0.04665	per Day
On-Peak Energy Charge - Base Level 1	$0.18881	$0.20653	$0.20892	per kWh
On-Peak Energy Charge - Base Level 2	$0.24915	$0.27284	$0.27585	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00625	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base Level 1	$0.08578	$0.09403	$0.09491	per kWh
Off-Peak Energy Charge - Base Level 2	$0.04792	$0.05253	$0.05303	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00192	$0.00000	$0.00000	per kWh
TSSM - General Secondary Transmission Substations - Metered				
Facilities Charge - Single Phase	$0.25000	$0.30000	$0.30000	per Day
Facilities Charge - Three Phase	$0.50000	$0.60000	$0.60000	per Day
Extra Meter Charge	$0.04665	$0.04665	$0.04665	per Day
Energy Charge - Base	$0.12611	$0.13816	$0.13945	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00362	$0.00000	$0.00000	per kWh
TSSU - General Secondary Transmission Substations - UnMetered				
Facilities Charge	$4.00	$4.00	$4.00	per Month
Energy Charge - Base	$0.12611	$0.13816	$0.13945	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00362	$0.00000	$0.00000	per kWh
TE1 - General Secondary Telecom Equipment - UnMetered				
Facilities Charge	$4.00	$4.00	$4.00	per Month
Energy Charge - Base	$0.12611	$0.13816	$0.13945	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00362	$0.00000	$0.00000	per kWh
ERER1 & ERER3 Renewable Rider				
Energy for Tomorrow - 25%	$0.00347	$0.00600	$0.00600	per kWh
Energy for Tomorrow - 50%	$0.00694	$0.01201	$0.01201	per kWh
Energy for Tomorrow - 100%	$0.01388	$0.02401	$0.02401	per kWh
ERER2 Renewable Rider				
Energy for Tomorrow - < 70,000 kWh per month	$0.01388	$0.02401	$0.02401	per kWh
Energy for Tomorrow - >= 70,000 kWh per month	$0.01118	$0.02266	$0.02266	per kWh
ERER4 Renewable Rider				
Energy for Tomorrow - 25%	$0.00280	$0.00567	$0.00567	per kWh
Energy for Tomorrow - 50%	$0.00559	$0.01133	$0.01133	per kWh
Energy for Tomorrow - 100%	$0.01118	$0.02266	$0.02266	per kWh
Energy Partner's Central Air Conditioning Load Control Credit				
6-Hour Shed	$0.40323	NA	NA	per Day (May 15 - Sep 15)
4-Hour Shed	$0.32258	NA	NA	per Day (May 15 - Sep 15)
75% Cycle	$0.09677	NA	NA	per Day (May 15 - Sep 15)
Peak-Time Rebates				
Energy Credit	$0.47000	NA	NA	per kWh adjusted
Cp1 -- General Primary Service - TOU				
Facilities Charge	$17.26027	$17.26027	$17.26027	per Day
On-Peak Energy Charge - Base (Low Voltage)	$0.07095	$0.07774	$0.07838	per kWh
On-Peak Energy Charge - Base (Medium Voltage)	$0.06985	$0.07660	$0.07724	per kWh
On-Peak Energy Charge - Base (High Voltage)	$0.06891	$0.07564	$0.07627	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00593	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base (Low Voltage)	$0.05053	$0.05315	$0.05357	per kWh
Off-Peak Energy Charge - Base (Medium Voltage)	$0.04974	$0.05238	$0.05279	per kWh
Off-Peak Energy Charge - Base (High Voltage)	$0.04818	$0.05072	$0.05112	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00183	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Base (Low Voltage)	$11.054	$12.838	$13.052	per kW
On-Peak Demand Charge - Base (Meduim Voltage)	$10.882	$12.650	$12.861	per kW
On-Peak Demand Charge - Base (High Voltage)	$10.736	$12.492	$12.700	per kW
On-Peak Demand Charge - Fuel Cost Adjustment	$0.000	$0.000	$0.000	per kW
Customer Demand Charge (Low Voltage)	$1.023	$1.326	$1.326	per kW
Customer Demand Charge (Medium Voltage)	$1.007	$1.306	$1.306	per kW
Customer Demand Charge (High Voltage)	$0.000	$0.000	$0.000	per kW

Wisconsin Electric Power Company
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Rate Schedules / Rate Descriptions	Present Rates	Authorized Rates in 2013	Authorized Rates in 2014	per Unit
Cp1R -- Gen. Pri. - Experimental Real-Time Pricing				
Facilities Charge	$23.01370	NA	NA	per Day
Access On-Peak Demand Charge (Low Voltage)	$11.054	NA	NA	per kW
Access On-Peak Demand Charge (Medium Voltage)	$10.882	NA	NA	per kW
Access On-Peak Demand Charge (High Voltage)	$10.736	NA	NA	per kW
Access Customer Demand Charge (Low Voltage)	$1.023	NA	NA	per kW
Access Customer Demand Charge (Medium Voltage)	$1.007	NA	NA	per kW
Access Customer Demand Charge (High Voltage)	$0.000	NA	NA	per kW
Cp2M -- General Primary Service - Interruptible				
Facilities Charge	$26.30137	$26.30137	NA	per Day
On-Peak Energy Charge - Base (Medium Voltage)	$0.06646	$0.07282	NA	per kWh
On-Peak Energy Charge - Base (High Voltage)	$0.06646	$0.07282	NA	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00593	$0.00000	NA	per kWh
Off-Peak Energy Charge - Base (Medium Voltage)	$0.04732	$0.04977	NA	per kWh
Off-Peak Energy Charge - Base (High Voltage)	$0.04732	$0.04977	NA	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00183	$0.00000	NA	per kWh
On-Peak Demand Charge - Base (Medium Voltage)	$5.522	$7.290	NA	per kW
On-Peak Demand Charge - Base (High Voltage)	$5.522	$7.290	NA	per kW
On-Peak Demand Charge - Fuel Cost Adjustment	$0.000	$0.000	NA	per kW
Customer Demand Charge (Medium Voltage)	$1.007	$1.306	NA	per kW
Customer Demand Charge (High Voltage)	$0.000	$0.000	NA	per kW
Cp3 -- Gen. Pri. Service - Curtailable				
Facilities Charge	$17.26027	$17.26027	$17.26027	per Day
On-Peak Energy Charge - Base (Low Voltage)	$0.07095	$0.07774	$0.07838	per kWh
On-Peak Energy Charge - Base (Medium Voltage)	$0.06985	$0.07660	$0.07724	per kWh
On-Peak Energy Charge - Base (High Voltage)	$0.06891	$0.07564	$0.07627	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00593	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base (Low Voltage)	$0.05053	$0.05315	$0.05357	per kWh
Off-Peak Energy Charge - Base (Medium Voltage)	$0.04974	$0.05238	$0.05279	per kWh
Off-Peak Energy Charge - Base (High Voltage)	$0.04818	$0.05072	$0.05112	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00183	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Base (Low Voltage)	$11.054	$12.838	$13.052	per kW
On-Peak Demand Charge - Base (Medium Voltage)	$10.882	$12.650	$12.861	per kW
On-Peak Demand Charge - Base (High Voltage)	$10.736	$12.492	$12.700	per kW
On-Peak Demand Charge - Fuel Cost Adjustment	$0.000	$0.000	$0.000	per kW
Customer Demand Charge (Low Voltage)	$1.023	$1.326	$1.326	per kW
Customer Demand Charge (Medium Voltage)	$1.007	$1.306	$1.306	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

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Rate Schedules / Rate Descriptions	Present Rates	Authorized Rates in 2013	Authorized Rates in 2014	per Unit
Cp3S -- Gen. Pri. - Seasonal Curtailable				
Facilities Charge	$17.26027	$17.26027	$17.26027	per Day
On-Peak Energy Charge - Base (Low Voltage)	$0.07095	$0.07774	$0.07838	per kWh
On-Peak Energy Charge - Base (Medium Voltage)	$0.06985	$0.07660	$0.07724	per kWh
On-Peak Energy Charge - Base (High Voltage)	$0.06891	$0.07564	$0.07627	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00593	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base (Low Voltage)	$0.05053	$0.05315	$0.05357	per kWh
Off-Peak Energy Charge - Base (Medium Voltage)	$0.04974	$0.05238	$0.05279	per kWh
Off-Peak Energy Charge - Base (High Voltage)	$0.04818	$0.05072	$0.05112	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00183	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Base (Low Voltage)	$11.054	$12.838	$13.052	per kW
On-Peak Demand Charge - Base (Medium Voltage)	$10.882	$12.650	$12.861	per kW
On-Peak Demand Charge - Base (High Voltage)	$10.736	$12.492	$12.700	per kW
On-Peak Demand Charge - Fuel Cost Adjustment	$0.000	$0.000	$0.000	per kW
Customer Demand Charge (Low Voltage)	$1.023	$1.326	$1.326	per kW
Customer Demand Charge (Medium Voltage)	$1.007	$1.306	$1.306	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 - Optional Standby				
Facilities Charge	$17.26027	$17.26027	$17.26027	per Day
Extra Meter Charge	$6.57534	$6.57534	$6.57534	per Day
On-Peak Energy Charge - Base (Low Voltage)	$0.07095	$0.07774	$0.07838	per kWh
On-Peak Energy Charge - Base (Medium Voltage)	$0.06985	$0.07660	$0.07724	per kWh
On-Peak Energy Charge - Base (High Voltage)	$0.06891	$0.07564	$0.07627	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00593	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base (Low Voltage)	$0.05053	$0.05315	$0.05357	per kWh
Off-Peak Energy Charge - Base (Medium Voltage)	$0.04974	$0.05238	$0.05279	per kWh
Off-Peak Energy Charge - Base (High Voltage)	$0.04818	$0.05072	$0.05112	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00183	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Base (Low Voltage)	$11.054	$12.838	$13.052	per kW
On-Peak Demand Charge - Base (Medium Voltage)	$10.882	$12.650	$12.861	per kW
On-Peak Demand Charge - Base (High Voltage)	$10.736	$12.492	$12.700	per kW
On-Peak Demand Charge - Fuel Cost Adjustment	$0.000	$0.000	$0.000	per kW
Customer Demand Charge (Low Voltage)	$1.023	$1.326	$1.326	per kW
Customer Demand Charge (Medium Voltage)	$1.007	$1.306	$1.306	per kW
Customer Demand Charge (High Voltage)	$0.000	$0.000	$0.000	per kW
Reserved Demand Charge (Low Voltage)	$1.95714	$1.787	$1.787	per kW
Reserved Demand Charge (Medium Voltage)	$1.92666	$1.761	$1.761	per kW
Reserved Demand Charge (High Voltage)	$0.90760	$1.739	$1.739	per kW
Standby Energy Charge (Low Voltage)	OOPC + 10%	OOPC + 10%	OOPC + 10%	per kWh
Standby Energy Charge (Medium Voltage)	OOPC + 10%	OOPC + 10%	OOPC + 10%	per kWh
Standby Energy Charge (High Voltage)	OOPC + 10%	OOPC + 10%	OOPC + 10%	per kWh
Minimum On-Peak Standby Energy Charge (Low Voltage)	$0.00000	$0.03000	$0.03000	per kWh
Minimum On-Peak Standby Energy Charge (Medium Voltage)	$0.00000	$0.03000	$0.03000	per kWh
Minimum On-Peak Standby Energy Charge (High Voltage)	$0.00000	$0.03000	$0.03000	per kWh
Minimum Off-Peak Standby Energy Charge (Low Voltage)	$0.00000	$0.02000	$0.02000	per kWh
Minimum Off-Peak Standby Energy Charge (Medium Voltage)	$0.00000	$0.02000	$0.02000	per kWh
Minimum Off-Peak Standby Energy Charge (High Voltage)	$0.00000	$0.02000	$0.02000	per kWh

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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)	$0.06985	$0.07660	$0.07724	per kWh
On-Peak Firm Energy Charge - Base (High Voltage)	$0.06891	$0.07564	$0.07627	per kWh
On-Peak Non Firm Energy Charge - Base (Medium Voltage)	$0.06646	$0.07282	$0.07353	per kWh
On-Peak Non Firm Energy Charge - Base (High Voltage)	$0.06558	$0.07191	$0.07261	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00593	$0.00000	$0.00000	per kWh
Off-Peak Firm Energy Charge - Base (Medium Voltage)	$0.04974	$0.05238	$0.05279	per kWh
Off-Peak Firm Energy Charge - Base (High Voltage)	$0.04818	$0.05072	$0.05112	per kWh
Off-Peak Non Firm Energy Charge - Base (Medium Voltage)	$0.04732	$0.04977	$0.05025	per kWh
Off-Peak Non Firm Energy Charge - Base (High Voltage)	$0.04584	$0.04819	$0.04866	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00183	$0.00000	$0.00000	per kWh
On-Peak Firm Demand Charge - Base (Medium Voltage)	$10.882	$12.650	$12.861	per kW
On-Peak Firm Demand Charge - Base (High Voltage)	$10.736	$12.492	$12.700	per kW
On-Peak Non Firm Demand Charge - Base (Medium Voltage)	$5.522	$7.290	$7.501	per kW
On-Peak Non Firm Demand Charge - Base (High Voltage)	$5.376	$7.132	$7.340	per kW
On-Peak Demand Charge - Fuel Cost Adjustment	$0.000	$0.000	$0.000	per kW
Customer Demand Charge (Medium Voltage)	$1.007	$1.306	$1.306	per kW
Customer Demand Charge (High Voltage)	$0.000	$0.000	$0.000	per kW
CGS1 Customer-Owned Generation - Over 20 kW				
Facilities Charge - Non Demand Metered	$0.04110	$0.04110	$0.04110	per Day
Facilities Charge - Demand Metered	$0.11507	$0.11507	$0.11507	per Day
On-Peak Purchase Price Secondary Voltage	LMP	LMP	LMP	per kWh
On-Peak Purchase Price Primary < 69 kV	LMP	LMP	LMP	per kWh
On-Peak Purchase Price Primary >= 69 kV	LMP	LMP	LMP	per kWh
Off-Peak Purchase Price Secondary Voltage	LMP	LMP	LMP	per kWh
Off-Peak Purchase Price Primary < 69 kV	LMP	LMP	LMP	per kWh
Off-Peak Purchase Price Primary >= 69 kV	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	$4.920	$0.285	$0.285	per kW
Capacity Payment Primary < 69 kV	$5.125	$0.296	$0.296	per kW
Capacity Payment Primary >= 69 kV	$5.042	$0.300	$0.300	per kW
Dispatched Energy Flowing Into System Secondary	$0.07304	$0.06486	$0.06486	per kWh
Dispatched Energy Flowing Into System Pri <69 kV	$0.07608	$0.06750	$0.06750	per kWh
Dispatched Energy Flowing Into System Pri >= 69 kV	$0.07486	$0.06836	$0.06836	per kWh
Dispatched Displaced Energy Secondary	$0.00000	$0.00000	$0.00000	per kWh
Dispatched Displaced Energy Primary < 69 kV	$0.00132	$0.00000	$0.00000	per kWh
Dispatched Displaced Energy Primary >= 69 kV	$0.00110	$0.00000	$0.00000	per kWh
Purchased Non-Dispatched Energy Secondary	$0.03641	$0.02478	$0.02478	per kWh
Purchased Non-Dispatched Energy Primary < 69 kV	$0.03793	$0.02579	$0.02579	per kWh
Purchased Non-Dispatched Energy Primary >= 69 kV	$0.03732	$0.02611	$0.02611	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 - 20 kW or less				
Flat Energy Rate	NA	$0.03712	$0.03712	per kWh
On-Peak Energy Rate	NA	$0.04545	$0.04545	per kWh
Off-Peak Energy Rate	NA	$0.03265	$0.03265	per kWh
St1 -- Optional TOU Street Lighting Service				
Facilities Charge - Single Phase	$0.26175	$0.30000	$0.30000	per Day
Facilities Charge - Three Phase	$0.52350	$0.60000	$0.60000	per Day
Extra Meter Charge	$0.04110	$0.04665	$0.04665	per Day
On-Peak Energy Charge	$0.24818	$0.27251	$0.27552	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00625	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge	$0.04548	$0.05150	$0.05195	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00192	$0.00000	$0.00000	per kWh

Wisconsin Electric Power Company
Present and Authorized Electric Rates

Rate Schedules / Rate Descriptions	Present Rates	Authorized Rates in 2013	Authorized Rates in 2014	per Unit
Gl1 - Area Lighting				
Standard High Pressure Sodium				
50 Watt	$10.08	$10.08	$10.08	per Month
70 Watt	$11.49	$11.67	$11.67	per Month
100 Watt	$13.26	$13.57	$13.57	per Month
150 Watt	$15.28	$15.81	$15.81	per Month
200 Watt	$17.90	$18.42	$18.42	per Month
250 Watt	$20.19	$20.90	$20.90	per Month
400 Watt	$26.53	$27.80	$27.80	per Month
Flood High Presure Sodium				
70 Watt	$13.20	$13.21	$13.21	per Month
100 Watt	$14.89	$15.07	$15.07	per Month
150 Watt	$16.91	$17.34	$17.34	per Month
200 Watt	$19.17	$19.83	$19.83	per Month
250 Watt	$21.40	$22.26	$22.26	per Month
400 Watt	$27.59	$28.98	$28.98	per Month
Standard Metal Halide				
175 Watt	$24.79	$25.24	$25.24	per Month
250 Watt	$25.68	$26.51	$26.51	per Month
400 Watt	$29.15	$30.69	$30.69	per Month
Flood Metal Halide				
175 Watt	$26.25	$26.55	$26.55	per Month
250 Watt	$26.73	$27.96	$27.96	per Month
400 Watt	$30.31	$31.94	$31.94	per Month
1000 Watt	$59.09	$60.86	$60.86	per Month
Poles	$2.57	$2.81	$2.81	per Month
Spans	$2.15	$2.74	$2.74	per Month
Energy Charge - Fuel Cost Adjustment	$0.00255	$0.00000	$0.00000	per kWh
Al1 - Alley Lighting				
0 - 10 Watt LED	NA	$2.33	$2.33	per Month
>10 - 20 Watt LED	NA	$2.66	$2.66	per Month
>20 - 30 Watt LED	NA	$3.07	$3.07	per Month
>30 - 40 Watt LED	NA	$3.49	$3.49	per Month
>40 - 50 Watt LED	NA	$3.90	$3.90	per Month
>50 - 60 Watt LED	NA	$4.31	$4.31	per Month
50 Watt HPS	$4.11	$4.31	$4.31	per Month
70 Watt HPS	$5.12	$5.40	$5.40	per Month
100 Watt HPS	$6.83	$7.27	$7.27	per Month
Energy Charge - Fuel Cost Adjustment	$0.00255	$0.00000	$0.00000	per kWh
Ms1 - Highway Lighting				
Facilities - 25 Watts or Less	NA	$3.06	$3.06000	
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	$0.12611	$0.13816	$0.13945	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00255	$0.00000	$0.00000	per kWh
Ms2 - Street Lighting				
Energy Charge - Base	$0.11350	$0.12434	$0.12551	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00255	$0.00000	$0.00000	per kWh

Wisconsin Electric Power Company
Present and Authorized Electric Rates

Rate Schedules / Rate Descriptions	Present Rates	Authorized Rates in 2013	Authorized Rates in 2014	per Unit
Ms3 - Street Lighting				
High Pressure Sodium Lamps				
50 Watt	$10.08	$10.08	$10.08	per Month
70 Watt	$11.49	$11.67	$11.67	per Month
100 Watt	$13.26	$13.57	$13.57	per Month
150 Watt	$15.28	$15.81	$15.81	per Month
200 Watt	$17.90	$18.42	$18.42	per Month
250 Watt	$20.19	$20.90	$20.90	per Month
400 Watt	$26.53	$27.80	$27.80	per Month
Metal Halide Lamps				
175 Watt	$24.79	$25.24	$25.24	per Month
250 Watt	$25.68	$26.51	$26.51	per Month
400 Watt	$29.15	$30.69	$30.69	per Month
Energy Charge - Fuel Cost Adjustment	$0.00255	$0.00000	$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	$2.11	$2.31	$2.31	per Month
70 Watt HPS	$3.12	$3.40	$3.40	per Month
100 Watt HPS	$4.83	$5.27	$5.27	per Month
150 Watt HPS	$6.84	$7.47	$7.47	per Month
175 Watt MH	$7.75	$8.46	$8.46	per Month
200 Watt HPS	$9.06	$9.88	$9.88	per Month
250 Watt HPS	$11.27	$12.30	$12.30	per Month
400 Watt HPS	$17.41	$19.00	$19.00	per Month
1000 Watt HPS	$40.55	$44.26	$44.26	per Month
Energy Charge - Fuel Cost Adjustment	$0.00255	$0.00000	$0.00000	per kWh
Mg1 - Municipal Defense Sirens				
Facilities Charge	$3.00	$3.00	$3.00	per Month
Energy Charge - Base	$0.12611	$0.13816	$0.13945	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00362	$0.00000	$0.00000	per kWh
Embedded Credits for Line Extensions				
Rg1, Rg2, Rg3 & Fg1 Single Phase	$914	$1,043	$1,043	per Customer
Rg1, Rg2, Rg3 & Fg1 Three Phase	$2,741	$3,128	$3,128	per Customer
Cg1 & Cg6 Single Phase	$1,002	$1,215	$1,215	per Customer
Cg1 & Cg6 Three Phase	$2,003	$2,429	$2,429	per Customer
Cg2, Cg3, Cg3A & Cg3C	$98.42	$90.50	$90.50	per kW
TE1	$3.70	$4.05	$4.05	per Customer
General Primary	$98.18	$90.32	$90.32	per kW
Standard Street Lighting	$47.27	$81.55	$81.55	per Lamp
Act 141 Costs Embedded in Base Rates				
Rg1, Rg2, Rg3, Fg1	$0.00140	$0.00184	$0.00184	per kWh
Cg1, Cg2, Cg3, Cg3A, Cg3C, Cg6, TSSM, TSSU,	$0.00174	$0.00152	$0.00152	per kWh
Cp1, Cp2m, Cp3, Cp3A, Cp4, CpFN	$0.00174	$0.00152	$0.00152	per kWh
Gl1, St1, Al1, Ms1, Ms2, Ms3, Ms4, Mg1, TE1	$0.00174	$0.00152	$0.00152	per kWh
Monitored Fuel Cost				
Unit Monitored Fuel Cost - Total	$0.02736	$0.03334	$0.03334	per kWh
Unit Monitored Fuel Cost Embedded in Base Rates	$0.02736	$0.03334	$0.03334	per kWh
Biomass Tax Grant Credit				
Rg1, Rg2, Rg3, Fg1, Cg1, Cg6, TSSM, TSSU	$0.00000	($0.00291)	($0.00081)	per kWh
Cg2	$0.00000	($0.00267)	($0.00074)	per kWh
Cg3, Cg3A, Cg3C, Cg3S, Cp1, Cp2m, Cp3, Cp3A, Cp3S, Cp4, CpFN	$0.00000	($0.00239)	($0.00066)	per kWh
Gl1, St1, Al1, Ms1, Ms2, Ms3, Ms4, Mg1, TE1	$0.00000	($0.00110)	($0.00030)	per kWh

Wisconsin Electric Power Company
Steam Revenue Summary
for Test Year ending December 31, 2013 & for 2014

	Revenue in TY2013 with Present Rates	Revenue in 2013 with Authorized Rates	Change 2013 Over Present	Revenue in 2014 with Authorized Rates	Change 2014 Over 2013
Downtown Milwaukee Steam [1]					
Ag-1 DMS	$20,630,998	$21,870,913	6.0%	$23,185,858	6.0%
Ag-4 DMS	$306,229	$322,289	5.2%	$339,504	5.3%
Total Downtown Milwaukee	$20,937,227	**$22,193,202**	**6.0%**	**$23,525,362**	**6.0%**
Wauwatosa Steam [2]					
Ag-1 Wauwatosa	$14,857,881	**$15,897,911**	**7.0%**	**$16,851,757**	**6.0%**
Total Steam	$35,795,109	$38,091,113	6.4%	$40,377,119	6.0%
Increases (for each year)		**$2,296,004**	**6.4%**	**$2,286,006**	**6.0%**
Total Cummulative 2-year Increase (Authorized over Present Rates)				**$4,582,010**	**12.0%**

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 Schedules / Rate Descriptions	Present Rates	Authorized Rates for 2013	Authorized Rates for 2014	per Unit
Ag1 Downtown Milwaukee Steam				
Facilities Charge per Customer Day	$0.66	$0.66	$0.66	per Day
Production Energy Charge	$4.95467	$5.18746	$5.56596	per MLbs
Distribution Energy Charge	$6.05743	$6.35641	$6.67528	per MLbs
Fuel Cost included in Base Production Rate	$4.20578	$3.77252	$3.77252	$/million BTU
Conversion Rate from million BTU production to MLBS sales	0.960	1.032	1.032	
Ag2 Downtown Milwaukee Steam				
Facilities Charge per Customer Day	$0.50	$0.50	$0.50	per Day
Production Energy Charge	$4.95467	$5.19741	$5.56596	per MLbs
Distribution Energy Charge	$0.00000	$0.00000	$0.00000	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	$4.20578	$3.77252	$3.77252	$/million BTU
Conversion Rate from million BTU production to MLBS sales	0.960	1.032	1.032	
Ag4 Downtown Milwaukee Steam				
Facilities Charge per Customer Day	$3.50	$3.50	$3.50	per Day
Production Energy Charge	$3.99973	$4.05614	$4.29850	per MLbs
Distribution Energy Charge	$6.05743	$6.35694	$6.67528	per MLbs
Fuel Cost included in Base Production Rate	$4.20578	$3.77252	$3.77252	$/million BTU
Conversion Rate from million BTU production to MLBS sales	0.960	1.032	1.032	
Ag1 Wauwatosa Steam				
Facilities Charge per Customer Day	$0.50	$0.50	$0.50	per Day
Production Energy Charge	$17.83904	$18.31060	$19.68429	per MLbs
Distribution Energy Charge	$5.13535	$5.06065	$4.98595	per MLbs
Fuel Cost included in Base Production Rate	$4.81694	$3.84045	$3.84045	$/million BTU
Conversion Rate from million BTU production to MLBS sales	1.456	1.585	1.585	
Embedded Credits				
Downtown Milwaukee	$12.00	$12.00	$12.00	per MLbs
Wauwatosa	$10.00	$13.00	$13.00	per MLbs

Wisconsin Electric - Gas Operations
Gas Revenue Summary
2013

Distribution Classes and Other Cost Categories	Volumes	Margin Revenue at Current Rates	+ Cost of Gas Revenues	= Rebundled Service Revs. by Dist. Class	+ Authorized Total Revenue Change/Class	= Total Bundled Rev. by Dist. Class	Percent Change Rebundled w/COG	Percent Change Rebundled w/o COG
Residential and Rely-A-Bill								
Residential (Rg-1)	334,686,472	$ 114,363,920	$ 156,153,591	$ 270,517,511	$ (4,884,007)	$ 265,633,504	(1.81)%	(4.27)%
Subtotal	334,686,472	$ 114,363,920	$ 156,153,591	$ 270,517,511	$ (4,884,007)	$ 265,633,504	(1.81)%	(4.27)%
Commercial & Industrial, g-1 (0 to 3,999)								
Firm Comm. Ind. (Fg-1)	36,113,274	$ 10,465,922	$ 16,991,612	$ 27,457,534	$ (656,245)	$ 26,801,289	(2.39)%	(6.27)%
Agricultural Seasonal Use (Ag-1)	217,461	51,843	85,796	137,638	(4,723)	132,916	(3.43)%	(9.11)%
Natural Gas Vehicles (NGV-1)	5,513	1,344	2,240	3,583	(118)	3,465	(3.29)%	(8.76)%
Transport Commercial (Tf-1)	-	-	-	-	-	-	-	-
Subtotal	36,336,248	$ 10,519,108	$ 17,079,647	$ 27,598,755	$ (661,085)	$ 26,937,670	(2.40)%	(6.28)%
Commercial & Industrial, g-2 (4,000 to 39,999)								
Firm Comm. Ind. (Fg-2)	104,098,849	$ 19,782,086	$ 48,453,709	$ 68,235,796	$ (1,342,875)	$ 66,892,921	(1.97)%	(6.79)%
Agricultural Seasonal Use (Ag-2)	1,474,987	266,087	580,484	846,572	(19,027)	827,544	(2.25)%	(7.15)%
Natural Gas Vehicles (NGV-2)	330,047	56,293	132,833	189,126	(4,258)	184,868	(2.25)%	(7.56)%
Transport Commercial (Tf-2)	1,983,982	284,750	(3,384)	281,365	(18,253)	263,113	(6.49)%	(6.41)%
Subtotal g-2	107,887,865	$ 20,389,216	$ 49,163,643	$ 69,552,859	$ (1,384,413)	$ 68,168,446	(1.99)%	(6.79)%
Commercial & Industrial, g-3 (40,000 to 99,999)								
Firm Comm. Ind. (Fg-3)	31,539,279	$ 4,834,849	$ 14,557,113	$ 19,391,961	$ (309,085)	$ 19,082,876	(1.59)%	(6.39)%
Agricultural Seasonal Use (Ag-3)	496,261	83,747	195,636	279,383	(4,863)	274,520	(1.74)%	(5.81)%
Natural Gas Vehicles (NGV-3)	59,200	9,045	24,785	33,830	(580)	33,250	(1.71)%	(6.41)%
Inter. Comm. Ind. (Ig-3)	-	-	-	-	-	-	-	-
Transport Commercial (Tf-3)	6,297,509	743,757	(10,742)	733,015	(38,415)	694,600	(5.24)%	(5.16)%
Subtotal g-3	38,392,249	$ 5,671,398	$ 14,766,791	$ 20,438,190	$ (352,943)	$ 20,085,246	(1.73)%	(6.22)%
Commercial & Industrial g-4 (100,000 to 499,999)								
Firm Comm. Ind. (Fg-4)	20,844,582	$ 2,601,848	$ 9,486,357	$ 12,088,205	$ (162,588)	$ 11,925,618	(1.35)%	(6.25)%
Agricultural Seasonal Use (Ag-4)	274,304	39,997	107,190	147,187	(2,140)	145,047	(1.45)%	(5.35)%
Inter. Comm. Ind. (Ig-4)	4,040,775	475,135	1,571,556	2,046,691	(31,518)	2,015,173	(1.54)%	(6.63)%
Transport Commercial (Tf-4)	43,830,299	3,739,621	(74,767)	3,664,854	(197,236)	3,467,618	(5.38)%	(5.27)%
Subtotal g-4	68,989,960	$ 6,856,601	$ 11,090,337	$ 17,946,938	$ (393,482)	$ 17,553,456	(2.19)%	(5.74)%
Commercial & Industrial g-5 (500,000 to 999,999)								
Firm Comm. Ind. (Fg-5)	1,825,598	$ 196,239	$ 830,363	$ 1,026,602	$ (6,937)	$ 1,019,665	(0.68)%	(3.54)%
Agricultural Seasonal Use (Ag-5)	-	-		-	-	-	-	-
Inter. Comm. Ind. (Ig-5)	749,991	75,999	291,690	367,689	(2,850)	364,839	(0.78)%	(3.75)%
Transport Commercial (Tf-5)	24,381,811	1,940,460	(41,591)	1,898,869	(34,135)	1,864,734	(1.80)%	(1.76)%
Subtotal g-5	26,957,400	$ 2,212,698	$ 1,080,462	$ 3,293,160	$ (43,922)	$ 3,249,239	(1.33)%	(1.98)%
Commercial & Industrial g-6 (1,000,000 to 7,999,999)								
Firm Comm. Ind. (Fg-6)	1,761,210	$ 147,318	$ 818,333	$ 965,650	$ (6,164)	$ 959,486	(0.64)%	(4.18)%
Inter. Comm. Ind. (Ig-6)	-	-	-	-	-	-	-	-
Transport Commercial (Tf-6)	103,026,513	5,608,944	(175,745)	5,433,199	(206,053)	5,227,146	(3.79)%	(3.67)%
Subtotal g-6	104,787,723	$ 5,756,261	$ 642,588	$ 6,398,849	$ (212,217)	$ 6,186,632	(3.32)%	(3.69)%
Commercial & Industrial, g-7 (8,000,000+)								
Firm Comm. Ind. (Fg-7)	0	-		-	-	-	-	-
Inter. Comm. Ind. (Ig-7)	-	-	-	-	-	-	-	-
Transport Commercial (Tf-7)	50,463,045	1,845,091	(86,081)	1,759,010	(95,880)	1,663,131	(5.45)%	(5.20)%
Subtotal g-7	50,463,045	$ 1,845,091	$ (86,081)	$ 1,759,010	$ (95,880)	$ 1,663,131	(5.45)%	(5.20)%
Total Gas Sales Rate Revenues	768,500,962	$ 167,614,295	$ 249,890,978	$ 417,505,272	$ (8,027,949)	$ 409,477,323	(1.92)%	(4.79)%
Power Generators	36,967,024	2,365,910	(23,276)	2,342,634	(33,495)	2,309,139	(1.43)%	(1.42)%
Total Gas Sales Revenue	805,467,986	$ 169,980,205	$ 249,867,702	$ 419,847,907	$ (8,061,444)	$ 411,786,463	(1.92)%	(4.74)%
Plus Other Revenue		$ 1,392,200	$ -	$ 1,392,200		$ 1,392,200	0.00%	-
Total Gas Operating Revenues		$ 171,372,405	$ 249,867,702	$ 421,240,107	$ (8,061,444)	$ 413,178,663	(1.91)%	(4.70)%

Wisconsin Electric - Gas Operations

Gas Rate Comparison
Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Residential		
Daily Basic Distribution Charge (Rg-1, Rt-1)	$ 0.29	$ 0.31
Transportation Administrative Charge (Rt-1)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Rg-1, Rt-1)	$ 0.1644	$ 0.1441
Daily Balancing Charge (Rg-1, Rt-1)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Rg-1)	$ 0.0369	$ 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)	$ 0.29	$ 0.31
Transportation Administrative Charge (Tf-1)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Fg-1, Ag-1, NGV-1, Tf-1)	$ 0.1644	$ 0.1441
Daily Balancing Charge (Fg-1, Ag-1, NGV-1, Tf-1)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Fg-1, NGV-1, Ag-1)	$ 0.0369	$ 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)	$ 0.1218	$ 0.1126
Daily Balancing Charge (Fg-2, Ag-2, NGV-2, Tf-2)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Fg-2, Ag-2, NGV-2)	$ 0.0363	$ 0.0326
Peak Day Backup Charge (Fg-2, Ag-2, NGV-2)	$ 0.0022	$ 0.0022

Wisconsin Electric - Gas Operations

Gas Rate Comparison
Present and Authorized Gas Rates

	Present Rates	Authorized Rates
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)	$ 0.0755	$ 0.0694
Daily Balancing Charge (Fg-3, Ag-3, NGV-3, Tf-3)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Fg-3, Ag-3, NGV-3)	$ 0.0363	$ 0.0326
Peak Day Backup Charge (Fg-3, Ag-3, NGV-3)	$ 0.0022	$ 0.0022
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)	$ 0.0649	$ 0.0604
Daily Balancing Charge (Fg-4, Ag-4, Ig-4, Tf-4)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Fg-4, Ag-4, Ig-4)	$ 0.0330	$ 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)	$ 0.0584	$ 0.0570
Daily Balancing Charge (Fg-5, Ag-5, Ig-5, Tf-5)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Fg-5, Ag-5, Ig-5)	$ 0.0241	$ 0.0217
Peak Day Backup Charge (Fg-5, Ag-5)	$ 0.0022	$ 0.0022

Wisconsin Electric - Gas Operations

Gas Rate Comparison
Present and Authorized Gas Rates

	Present Rates	Authorized Rates
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:		
Distribution Service Charge (Fg-6, Ig-6, Tf-6)	$ 0.0288	$ 0.0268
Demand Charge (Fg-6, Ig-6, Tf-6)	$ 0.0030	$ 0.0030
Daily Balancing Charge (Fg-6, Ig-6, Tf-6)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Fg-6, Ig-6)	$ 0.0149	$ 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:		
Distribution Service Charge (Fg-7, Ig-7, Tf-7)	$ 0.0182	$ 0.0163
Demand Charge (Fg-7, Ig-7, Tf-7)	$ 0.0024	$ 0.0024
Daily Balancing Charge (Fg-7, Ig-7, Tf-7)	$ 0.0018	$ 0.0018
Competitive Supply Charge (Fg-7, Ig-7)	$ 0.0149	$ 0.0119
Peak Day Backup Charge (Fg-7)	$ 0.0022	$ 0.0022
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	$ 0.0117	$ 0.0087
Pt-6	$ 0.0294	$ 0.0265
Pt-7	$ 0.0287	$ 0.0258
Pt-8	$ 0.0285	$ 0.0256
Pt-9	$ 0.0015	$ 0.0015
Demand Charge	$ -	$ -
Pt-9	$ 0.0150	$ 0.0150

Wisconsin Electric - Gas Operations

Gas Rate Comparison
Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Base Gas Cost Rates:		
Average Peak Day Demand Costs - Volumetric	$ 0.1493	$ 0.0929
Average Peak Day Demand Costs - Contracted	$ 0.0315	$ 0.0175
Average Annual Contract Demand Costs	$ 0.0188	$ 0.0241
Average Annual Demand Costs	$ 0.0188	$ 0.0241
Average Commodity Costs	$ 0.6221	$ 0.3665
Average Surcharge Costs	$ -	$ -
LDC Reserved Gas Supply - Commodity Charge	$ 0.6340	$ 0.3864
Gas Lost And Unaccounted For Rate	$ (0.0054)	$ (0.0017)
Daily Cashout Charges:		
Competitive Supply	$ 0.0203	$ 0.0177
Peak Day Backup	$ 0.0022	$ 0.0022
Act 141 Volumetric Distribution Factors 1/		
Residential	$ 0.0089	$ 0.0124
Commercial G-1 (0 to 3,999)	$ 0.0161	$ 0.0224
Commercial G-2 (4,000 to 39,999)	$ 0.0161	$ 0.0224
Commercial G-3 (40,000 to 99,999)	$ 0.0161	$ 0.0224
Commercial G-4 (100,000 to 499,999)	$ 0.0161	$ 0.0224
Commercial G-5 (500,000 to 999,999)	$ 0.0161	$ 0.0224
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 factors are included in the above volumetric Distribution Service Charges.

Wisconsin Electric - Gas Operations
Monthly Residential Bill Impact Analysis

Gas Costs	Summer	Winter
Firm Sales Service	0.3889	0.4818

Monthly Use Therms		Present Customer Charge	Present Volumetric Distribution Charges	Total Monthly Cost	Gas Costs	Total Costs	Authorized Customer Charge	Authorized Volumetric Distribution Charges	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		$ 8.82	$ 1.03	$ 9.85	$ 1.94	$ 11.79	$ 9.43	$ 0.91	$ 10.34	$ 1.94	$ 12.28	$ 0.49	4.14%
15		$ 8.82	$ 3.08	$ 11.90	$ 5.83	$ 17.73	$ 9.43	$ 2.72	$ 12.15	$ 5.83	$ 17.98	$ 0.25	1.40%
21	avg.	$ 8.82	$ 4.31	$ 13.13	$ 8.17	$ 21.30	$ 9.43	$ 3.81	$ 13.24	$ 8.17	$ 21.40	$ 0.10	0.49%
35		$ 8.82	$ 7.19	$ 16.01	$ 13.61	$ 29.62	$ 9.43	$ 6.35	$ 15.77	$ 13.61	$ 29.39	$ (0.23)	(0.78)%
50		$ 8.82	$ 10.27	$ 19.09	$ 19.45	$ 38.53	$ 9.43	$ 9.07	$ 18.49	$ 19.45	$ 37.94	$ (0.59)	(1.54)%
75		$ 8.82	$ 15.40	$ 24.22	$ 29.17	$ 53.39	$ 9.43	$ 13.60	$ 23.03	$ 29.17	$ 52.20	$ (1.19)	(2.23)%
100		$ 8.82	$ 20.53	$ 29.35	$ 38.89	$ 68.24	$ 9.43	$ 18.13	$ 27.56	$ 38.89	$ 66.45	$ (1.79)	(2.63)%
108		$ 8.82	$ 22.17	$ 30.99	$ 42.00	$ 73.00	$ 9.43	$ 19.58	$ 29.01	$ 42.00	$ 71.01	$ (1.98)	(2.72)%
150		$ 8.82	$ 30.80	$ 39.62	$ 58.34	$ 97.95	$ 9.43	$ 27.20	$ 36.62	$ 58.34	$ 94.96	$ (2.99)	(3.05)%
200		$ 8.82	$ 41.06	$ 49.88	$ 77.78	$ 127.67	$ 9.43	$ 36.26	$ 45.69	$ 77.78	$ 123.47	$ (4.19)	(3.28)%
300		$ 8.82	$ 61.59	$ 70.41	$ 116.68	$ 187.09	$ 9.43	$ 54.39	$ 63.82	$ 116.68	$ 180.50	$ (6.59)	(3.52)%
Rg-1: Residential Firm Sales Service During Winter Months													
5	0	$ 8.82	$ 1.03	$ 9.85	$ 2.41	$ 12.26	$ 9.43	$ 0.91	$ 10.34	$ 2.41	$ 12.74	$ 0.49	3.98%
15	0	$ 8.82	$ 3.08	$ 11.90	$ 7.23	$ 19.13	$ 9.43	$ 2.72	$ 12.15	$ 7.23	$ 19.38	$ 0.25	1.30%
21	0	$ 8.82	$ 4.31	$ 13.13	$ 10.12	$ 23.25	$ 9.43	$ 3.81	$ 13.24	$ 10.12	$ 23.35	$ 0.10	0.45%
35	0	$ 8.82	$ 7.19	$ 16.01	$ 16.86	$ 32.87	$ 9.43	$ 6.35	$ 15.77	$ 16.86	$ 32.64	$ (0.23)	(0.70)%
50	0	$ 8.82	$ 10.27	$ 19.09	$ 24.09	$ 43.18	$ 9.43	$ 9.07	$ 18.49	$ 24.09	$ 42.59	$ (0.59)	(1.37)%
75	0	$ 8.82	$ 15.40	$ 24.22	$ 36.14	$ 60.35	$ 9.43	$ 13.60	$ 23.03	$ 36.14	$ 59.16	$ (1.19)	(1.97)%
100	0	$ 8.82	$ 20.53	$ 29.35	$ 48.18	$ 77.53	$ 9.43	$ 18.13	$ 27.56	$ 48.18	$ 75.74	$ (1.79)	(2.31)%
108	avg.	$ 8.82	$ 22.17	$ 30.99	$ 52.04	$ 83.03	$ 9.43	$ 19.58	$ 29.01	$ 52.04	$ 81.05	$ (1.98)	(2.39)%
150	0	$ 8.82	$ 30.80	$ 39.62	$ 72.27	$ 111.89	$ 9.43	$ 27.20	$ 36.62	$ 72.27	$ 108.90	$ (2.99)	(2.67)%
200	0	$ 8.82	$ 41.06	$ 49.88	$ 96.36	$ 146.24	$ 9.43	$ 36.26	$ 45.69	$ 96.36	$ 142.05	$ (4.19)	(2.87)%
300	0	$ 8.82	$ 61.59	$ 70.41	$ 144.55	$ 214.96	$ 9.43	$ 54.39	$ 63.82	$ 144.55	$ 208.37	$ (6.59)	(3.07)%
Avg. Annual Residential Billing													
774		$ 105.85	$ 158.90	$ 264.75	$ 361.22	$ 625.98	$ 113.15	$ 140.33	$ 253.48	$ 361.22	$ 614.70	$ (11.28)	(1.80)%

Wisconsin Gas Company LLC
Gas Revenue Summary
2013

Distribution Classes and Other Cost Categories	Volumes	Margin Revenue at Current Rates	+ Cost of Gas Revenues	= Rebundled Service Revs. by Dist. Class	+ Authorized Total Revenue Change/Class	= Total Bundled Rev. by Dist. Class	Percent Change Rebundled w/COG	Percent Change Rebundled w/o COG
Residential and Rely-A-Bill								
Residential (Rg-1)	430,725,051	$ 174,248,804	$ 213,475,696	$ 387,724,500	$ (20,846,067)	$ 366,878,433	(5.38)%	(11.96)%
Subtotal	430,725,051	$ 174,248,804	$ 213,475,696	$ 387,724,500	$ (20,846,067)	$ 366,878,433	(5.38)%	(11.96)%
Commercial & Industrial, G-1 (0 to 3,999)								
Firm Comm. Ind. (Fg-1)	51,476,553	$ 17,857,197	$ 25,775,687	$ 43,632,884	$ (2,491,372)	$ 41,141,512	(5.71)%	(13.95)%
Agricultural Seasonal Use (Ag-1)	152,491	43,801	62,291	106,091	(7,378)	98,714	(6.95)%	(16.84)%
Natural Gas Vehicles 1 (NGV-1)	-	-	-	-	-	-	-	-
Ornamental Lighting (OL)	-	3,590		3,590	(398)	3,192	(11.09)%	(11.09)%
Transport Commercial (Tf-1)	49,831	16,385	(55)	16,330	(2,256)	14,074	(13.82)%	(13.77)%
Subtotal	51,678,875	$ 17,920,974	$ 25,837,922	$ 43,758,895	$ (2,501,404)	$ 41,257,491	(5.72)%	(13.96)%
Commercial & Industrial, G-2 (4,000 to 39,999)								
Firm Comm. Ind. (Fg-2)	144,968,172	$ 33,863,608	$ 71,630,675	$ 105,494,283	$ (5,175,221)	$ 100,319,063	(4.91)%	(15.28)%
Agricultural Seasonal Use (Ag-2)	1,095,331	240,825	442,357	683,182	(39,106)	644,076	(5.72)%	(16.24)%
Natural Gas Vehicles 2 (NGV-2)	162,089	34,893	67,736	102,629	(5,787)	96,842	(5.64)%	(16.58)%
Transport Commercial 2 (Tf-2)	6,766,744	1,286,710	(7,530)	1,279,181	(221,274)	1,057,907	(17.30)%	(17.20)%
Subtotal G-2	152,992,336	$ 35,426,037	$ 72,133,238	$ 107,559,275	$ (5,441,387)	$ 102,117,887	(5.06)%	(15.36)%
Commercial & Industrial, G-3 (40,000 to 99,999)								
Firm Comm. Ind. (Fg-3)	40,867,084	$ 7,978,588	$ 20,071,809	$ 28,050,397	$ (1,087,561)	$ 26,962,835	(3.88)%	(13.63)%
Agricultural Seasonal Use (Ag-3)	781,025	155,702	320,900	476,602	(20,773)	455,829	(4.36)%	(13.34)%
Natural Gas Vehicles 3 (NGV-3)	91,223	16,595	37,737	54,332	(2,428)	51,904	(4.47)%	(14.63)%
Inter. Comm. Ind. (Ig-3)	212,648	40,032	84,503	124,535	(5,654)	118,881	(4.54)%	(14.12)%
Transport Commercial 3 (Tf-3)	19,238,635	2,940,888	(21,408)	2,919,480	(457,881)	2,461,600	(15.68)%	(15.57)%
Subtotal G-3	61,190,615	$ 11,131,806	$ 20,493,541	$ 31,625,346	$ (1,574,297)	$ 30,051,049	(4.98)%	(14.14)%
Commercial & Industrial G-4 (100,000 to 499,999)								
Firm Comm. Ind. (Fg-4)	21,281,902	$ 3,350,390	$ 10,242,404	$ 13,592,795	$ (373,645)	$ 13,219,149	(2.75)%	(11.15)%
Agricultural Seasonal Use (Ag-4)	776,233	135,198	316,456	451,654	(13,661)	437,993	(3.02)%	(10.10)%
Inter. Comm. Ind. (Ig-4)	2,356,273	370,003	936,341	1,306,344	(41,467)	1,264,876	(3.17)%	(11.21)%
Transport Commercial 4 (Tf-4)	88,308,615	9,255,774	(98,266)	9,157,508	(1,315,798)	7,841,709	(14.37)%	(14.22)%
Subtotal g-4	112,723,023	$ 13,111,365	$ 11,396,935	$ 24,508,300	$ (1,744,572)	$ 22,763,728	(7.12)%	(13.31)%
Commercial & Industrial G-5 (500,000 to 999,999)								
Firm Comm. Ind. (Fg-5)	1,208,415	$ 153,466	$ 619,111	$ 772,577	$ (16,813)	$ 755,764	(2.18)%	(10.96)%
Agricultural Seasonal Use (Ag-5)	0	-	-	-	-	-	-	-
Inter. Comm. Ind. (Ig-5)	2,131,793	270,777	847,137	1,117,914	(22,596)	1,095,318	(2.02)%	(8.34)%
Transport Commercial 5 (Tf-5)	44,219,071	3,875,412	(39,514)	3,835,899	(375,864)	3,460,035	(9.80)%	(9.70)%
Subtotal G-5	47,559,279	$ 4,299,656	$ 1,426,734	$ 5,726,390	$ (415,273)	$ 5,311,116	(7.25)%	(9.66)%
Commercial & Industrial G-6 (1,000,000 to 7,999,999)								
Firm Comm. Ind. (Fg-6)	1,350,103	$ 137,301	$ 649,949	$ 787,251	$ (19,703)	$ 767,548	(2.50)%	(14.35)%
Inter. Comm. Ind. (Ig-6)	6,627,973	629,988	2,633,838	3,263,826	(58,322)	3,205,504	(1.79)%	(9.26)%
Transport Commercial 6 (Tf-6)	187,407,991	10,214,484	(208,539)	10,005,945	(1,255,631)	8,750,315	(12.55)%	(12.29)%
Subtotal g-6	195,386,067	$ 10,981,773	$ 3,075,249	$ 14,057,022	$ (1,333,656)	$ 12,723,366	(9.49)%	(12.14)%
Commercial & Industrial, G-7 (8,000,000+)								
Firm Comm. Ind. (Fg-7)	-	$ -	$ -	$ -	$ -	$ -	-	-
Inter. Comm. Ind. (Ig-7)	-	-		-	-	-	-	-
Transport Commercial 7 (Tf-7)	26,733,152	1,392,443	(29,747)	1,362,696	(247,231)	1,115,465	(18.14)%	(17.76)%
Subtotal G-7	26,733,152	$ 1,392,443	$ (29,747)	$ 1,362,696	$ (247,231)	$ 1,115,465	(18.14)%	(17.76)%
Total Gas Rate Sales Revenues	1,078,988,398	$ 268,512,857	$ 347,809,567	$ 616,322,423	$ (34,103,887)	$ 582,218,536	(5.53)%	(12.70)%
Special Contracts	319,453,478	7,955,770	(29,282)	7,926,488	(178,846)	7,747,642	(2.26)%	(2.25)%
Total Gas Sales Revenues	1,398,441,876	$ 276,468,627	$ 347,780,285	$ 624,248,912	$ (34,282,733)	$ 589,966,178	(5.49)%	(12.40)%
Plus Other Revenue		$ 4,544,100	$ -	$ 4,544,100		$ 4,544,100	0.00%	-
Total Gas Operating Revenues		$ 281,012,727	$ 347,780,285	$ 628,793,012	$ (34,282,733)	$ 594,510,278	(5.45)%	(12.20)%

Wisconsin Gas Company LLC

Gas Rate Comparison
Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Residential		
Daily Basic Distribution Charge (Rg-1, Rt-1)	$ 0.31	$ 0.31
Transportation Administrative Charge (Rt-1)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Rg-1, Rt-1)	$ 0.2091	$ 0.1638
Daily Balancing Charge (Rg-1, Rt-1)	$ 0.0013	$ 0.0013
Competitive Supply Charge (Rg-1)	$ 0.0490	$ 0.0459
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	$ 0.31
Transportation Administrative Charge (Tf-1)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Fg-1, Ag-1, NGV-1, Tf-1)	$ 0.2091	$ 0.1638
Daily Balancing Charge (Fg-1, Ag-1, NGV-1, Tf-1)	$ 0.0013	$ 0.0013
Competitive Supply Charge (Fg-1, NGV-1, Ag-1)	$ 0.0490	$ 0.0459
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)	$ 0.1558	$ 0.1231
Daily Balancing Charge (Fg-2, Ag-2, NGV-2, Tf-2)	$ 0.0013	$ 0.0013
Competitive Supply Charge (Fg-2, Ag-2, NGV-2)	$ 0.0483	$ 0.0453
Peak Day Backup Charge (Fg-2, Ag-2, NGV-2)	$ 0.0003	$ 0.0003

Wisconsin Gas Company LLC

Gas Rate Comparison
Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Commercial (40,000 to 99,999)		
Daily Basic Distribution Charge (Fg-3, Ag-3, NGV-3, Tf-3)	$ 5.80	$ 5.80
Transportation Administrative Charge (Tf-3)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Fg-3, Ag-3, NGV-3, Tf-3)	$ 0.1122	$ 0.0884
Daily Balancing Charge (Fg-3, Ag-3, NGV-3, Tf-3)	$ 0.0013	$ 0.0013
Competitive Supply Charge (Fg-3, Ag-3, NGV-3)	$ 0.0449	$ 0.0421
Peak Day Backup Charge (Fg-3, Ag-3, NGV-3)	$ 0.0003	$ 0.0003
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)	$ 0.0792	$ 0.0643
Daily Balancing Charge (Fg-4, Ag-4, Ig-4, Tf-4)	$ 0.0013	$ 0.0013
Competitive Supply Charge (Fg-4, Ag-4, Ig-4)	$ 0.0440	$ 0.0413
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)	$ 0.0619	$ 0.0534
Daily Balancing Charge (Fg-5, Ag-5, Ig-5, Tf-5)	$ 0.0013	$ 0.0013
Competitive Supply Charge (Fg-5, Ag-5, Ig-5)	$ 0.0330	$ 0.0309
Peak Day Backup Charge (Fg-5, Ag-5)	$ 0.0003	$ 0.0003

Wisconsin Gas Company LLC

Gas Rate Comparison
Present and Authorized Gas Rates

	Present Rates	Authorized Rates
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:		
Distribution Service Charge (Fg-6, Ig-6, Tf-6)	$ 0.0333	$ 0.0266
Demand Charge (Fg-6, Ig-6, Tf-6)	$ 0.0026	$ 0.0026
Daily Balancing Charge (Fg-6, Ig-6, Tf-6)	$ 0.0013	$ 0.0013
Competitive Supply Charge (Fg-6, Ig-6)	$ 0.0330	$ 0.0309
Peak Day Backup Charge (Fg-6)	$ 0.0003	$ 0.0003
Commercial (8,000,000 and over)		
Daily Basic Distribution Charge (Fg-7, Ig-7, Tf-7)	$ 500.00	$ 450.00
Transportation Administrative Charge (Tf-7)	$ 2.00	$ 2.00
Volumetric Charges:		
Distribution Service Charge (Fg-7, Ig-7, Tf-7)	$ 0.0259	$ 0.0187
Demand Charge (Fg-7, Ig-7, Tf-7)	$ 0.0018	$ 0.0018
Daily Balancing Charge (Fg-7, Ig-7, Tf-7)	$ 0.0013	$ 0.0013
Competitive Supply Charge (Fg-7, Ig-7)	$ 0.0220	$ 0.0220
Peak Day Backup Charge (Fg-7)	$ 0.0003	$ 0.0003

Wisconsin Gas Company LLC

Gas Rate Comparison
Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Monthly Ornamental Lighting	$ 15.75	$ 14.00
Base Gas Cost Rates:		
Average Peak Day Demand Costs - Volumetric	$ 0.1568	$ 0.1183
Average Peak Day Demand Costs - Contracted	$ 0.0431	$ 0.0200
Average Annual Contract Demand Costs	$ 0.0224	$ 0.0331
Average Annual Demand Costs	$ 0.0224	$ 0.0331
Average Commodity Costs	$ 0.6080	$ 0.3654
Average Surcharge Costs	$ -	$ -
LDC Reserved Gas Supply - Commodity Charge	$ 0.6442	$ 0.3993
Gas Lost And Unaccounted For Rate	$ (0.0053)	$ (0.0011)
Daily Cashout Charges:		
Competitive Supply	$ 0.0359	$ 0.0336
Peak Day Backup	$ 0.0003	$ 0.0003
Act 141 Volumetric Distribution Rates 1/		
Residential	$ 0.0093	$ 0.0111
Commercial G-1 (0 to 3,999)	$ 0.0150	$ 0.0167
Commercial G-2 (4,000 to 39,999)	$ 0.0150	$ 0.0167
Commercial G-3 (40,000 to 99,999)	$ 0.0150	$ 0.0167
Commercial G-4 (100,000 to 499,999)	$ 0.0150	$ 0.0167
Commercial G-5 (500,000 to 999,999)	$ 0.0150	$ 0.0167
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.

Wisconsin Gas LLC
Monthly Residential Bill Impact Analysis

Gas Costs	Summer	Winter
Firm Sales Service	0.3974	0.5157

Monthly Use Therms		Present Customer Charge	Present Volumetric Distribution Charges	Total Monthly Cost	Gas Costs	Total Costs	Authorized Customer Charge	Authorized Volumetric Distribution Charges	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	$ 1.30	$ 10.73	$ 1.99	$ 12.72	$ 9.43	$ 1.06	$ 10.49	$ 1.99	$ 12.47	$ (0.24)	(1.90)%
15		$ 9.43	$ 3.90	$ 13.33	$ 5.96	$ 19.29	$ 9.43	$ 3.17	$ 12.60	$ 5.96	$ 18.56	$ (0.73)	(3.76)%
22	avg.	$ 9.43	$ 5.72	$ 15.14	$ 8.74	$ 23.89	$ 9.43	$ 4.65	$ 14.08	$ 8.74	$ 22.82	$ (1.06)	(4.46)%
35		$ 9.43	$ 9.09	$ 18.52	$ 13.91	$ 32.43	$ 9.43	$ 7.40	$ 16.83	$ 13.91	$ 30.74	$ (1.69)	(5.22)%
50		$ 9.43	$ 12.99	$ 22.42	$ 19.87	$ 42.29	$ 9.43	$ 10.57	$ 20.00	$ 19.87	$ 39.87	$ (2.42)	(5.72)%
75		$ 9.43	$ 19.49	$ 28.91	$ 29.80	$ 58.72	$ 9.43	$ 15.86	$ 25.28	$ 29.80	$ 55.09	$ (3.63)	(6.18)%
100		$ 9.43	$ 25.98	$ 35.41	$ 39.74	$ 75.15	$ 9.43	$ 21.14	$ 30.57	$ 39.74	$ 70.31	$ (4.84)	(6.44)%
108		$ 9.43	$ 28.06	$ 37.49	$ 42.92	$ 80.40	$ 9.43	$ 22.83	$ 32.26	$ 42.92	$ 75.18	$ (5.23)	(6.50)%
150		$ 9.43	$ 38.97	$ 48.40	$ 59.61	$ 108.01	$ 9.43	$ 31.71	$ 41.14	$ 59.61	$ 100.75	$ (7.26)	(6.72)%
200		$ 9.43	$ 51.96	$ 61.39	$ 79.48	$ 140.87	$ 9.43	$ 42.28	$ 51.71	$ 79.48	$ 131.19	$ (9.68)	(6.87)%
300		$ 9.43	$ 77.94	$ 87.37	$ 119.21	$ 206.58	$ 9.43	$ 63.42	$ 72.85	$ 119.21	$ 192.06	$ (14.52)	(7.03)%
Rg-1: Residential Firm Sales Service During Winter Months													
5		$ 9.43	$ 1.30	$ 10.73	$ 2.58	$ 13.31	$ 9.43	$ 1.06	$ 10.49	$ 2.58	$ 13.06	$ (0.24)	(1.82)%
15		$ 9.43	$ 3.90	$ 13.33	$ 7.74	$ 21.06	$ 9.43	$ 3.17	$ 12.60	$ 7.74	$ 20.34	$ (0.73)	(3.45)%
22		$ 9.43	$ 5.72	$ 15.14	$ 11.35	$ 26.49	$ 9.43	$ 4.65	$ 14.08	$ 11.35	$ 25.43	$ (1.06)	(4.02)%
35		$ 9.43	$ 9.09	$ 18.52	$ 18.05	$ 36.57	$ 9.43	$ 7.40	$ 16.83	$ 18.05	$ 34.88	$ (1.69)	(4.63)%
50		$ 9.43	$ 12.99	$ 22.42	$ 25.79	$ 48.21	$ 9.43	$ 10.57	$ 20.00	$ 25.79	$ 45.79	$ (2.42)	(5.02)%
75		$ 9.43	$ 19.49	$ 28.91	$ 38.68	$ 67.59	$ 9.43	$ 15.86	$ 25.28	$ 38.68	$ 63.96	$ (3.63)	(5.37)%
100		$ 9.43	$ 25.98	$ 35.41	$ 51.57	$ 86.98	$ 9.43	$ 21.14	$ 30.57	$ 51.57	$ 82.14	$ (4.84)	(5.56)%
108	avg.	$ 9.43	$ 28.06	$ 37.49	$ 55.70	$ 93.19	$ 9.43	$ 22.83	$ 32.26	$ 55.70	$ 87.96	$ (5.23)	(5.61)%
150		$ 9.43	$ 38.97	$ 48.40	$ 77.36	$ 125.76	$ 9.43	$ 31.71	$ 41.14	$ 77.36	$ 118.50	$ (7.26)	(5.77)%
200		$ 9.43	$ 51.96	$ 61.39	$ 103.14	$ 164.53	$ 9.43	$ 42.28	$ 51.71	$ 103.14	$ 154.85	$ (9.68)	(5.88)%
300		$ 9.43	$ 77.94	$ 87.37	$ 154.72	$ 242.09	$ 9.43	$ 63.42	$ 72.85	$ 154.72	$ 227.57	$ (14.52)	(6.00)%
Avg. Annual Residential Billing													
780		$ 113.15	$ 202.64	$ 315.79	$ 386.64	$ 702.44	$ 113.15	$ 164.89	$ 278.04	$ 386.64	$ 664.68	$ (37.75)	(5.37)%

2013 Approved Fuel Cost Plan
5-UR-106

	Fuel Costs	Net MWh Produced	Fuel Cost per Net MWh Produced	Cumulative Cost per MWh
January	$ 80,130,000	2,549,889	$ 31.42	$ 31.42
February	72,826,000	2,293,280	31.76	31.58
March	73,779,000	2,424,990	30.42	31.20
April	66,877,000	2,226,355	30.04	30.92
May	80,028,000	2,303,068	34.75	31.67
June	90,617,000	2,551,143	35.52	32.36
July	108,785,000	2,792,605	38.95	33.43
August	107,338,000	2,793,215	38.43	34.13
September	83,423,000	2,389,929	34.91	34.21
October	69,307,000	2,361,665	29.35	33.75
November	68,148,000	2,236,840	30.47	33.48
December	79,270,000	2,486,968	31.87	33.34
	$ 980,528,000	29,409,947	$ 33.34	$ 33.34