BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC, both d/b/a We Energies, for Wisconsin Electric Power Company to Increase Its Electric, Natural Gas, and Steam Rates and for Wisconsin Gas LLC to Increase its Natural Gas Rates — Docket No. 05-UR-104

Limited Issue 2011 Fuel Reopener

DIRECT TESTIMONY OF JEFF KNITTER
ON BEHALF OF WISCONSIN ELECTRIC POWER COMPANY

Q. Please state your name and title.

A. My name is Jeff Knitter. I am the Manager – Special Projects in Wisconsin Electric Power Company's Wholesale Energy and Fuels Department.

Q. Have you previously testified before the Public Service Commission of Wisconsin?

A. Yes, most recently in the Edgewater 5 SCR docket (05-CE-137). I have also testified in the Elm Road Generating Station and Port Washington Generating Station CPCN dockets and have recently submitted testimony in the Rothschild Biomass Cogeneration Facility docket (6630-CE-305).

Q. What is the purpose of your testimony in this proceeding?

A. In Wisconsin Electric's most recent general rate case, Docket No. 05-UR-104, which established rates for test year 2010, the Commission in its Final Decision, dated December 18, 2009, (2009 Final Decision) authorized the Company to reopen the docket in 2010 to review updated 2011 fuel costs. The Company has filed an application to accomplish the authorized update and my testimony is in support of that application. More specifically, I will indicate what we now expect our aggregate 2011 fuel costs to be and I will indicate by what amount those costs exceed the amount currently included in our rates. I will also explain what "drivers" account for the increase in 2011 fuel cost over what is currently in rates.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring Exhibits 1.1 and 1.2 (JEK).

Q. Please continue.

A. On March 25, 2010, the Commission issued an Interim Decision and Order (2010 Interim Decision) in Docket No. 6630-FR-102. In that 2010 Interim Decision, the Company's monitored fuel costs on a total system basis were established at $886.8 million, or $29.76/MWh. This is the level of monitored fuel cost that is currently reflected in rates. We currently project 2011 total system monitored fuel costs at $932.2 million, which is approximately $45.4 million more than the amount authorized by the 2010 Interim Decision. To reflect these increased costs for 2011 the Company is requesting a monitored fuel cost recovery rate of $31.29/MWh, which is an increase of $1.53/MWh from the $29.76/MWh rate approved in the 2010 Interim Decision.

Q. What are the primary factors that cause projected 2011 monitored fuel costs to differ from the monitored fuel costs currently included in rates based on the 2010 Interim Decision?

A. I have identified six categories of factors contributing to the change in 2011 monitored fuel costs compared to the current level. Those six categories and their net impact on monitored fuel cost are as follows:

1. Adjustments to the PROMOD model, including translating the 2010 PROMOD case into 2011: -$2.7 million
2. Increased coal costs: +$57.7 million

3. MISO energy market items: -$5.9 million
4. Updated resource supply plan: -$5.3 million
5. Impacts of transmission congestion: +19.5 million
6. Other changes in monitored fuel costs: -$17.8 million

As you can see, the increased cost due to transmission congestion is more than offset by net cost reductions in four of the other categories. In particular, the new Elm Road Unit 2, built as part of Power the Future, will be in service for all of 2011, which has the effect of reducing monitored fuel costs by $24.0 million. The principal factor driving the net increase in cost is increased coal costs. In fact, in our test year 2010 base rate case, we indicated the likelihood of higher coal costs in 2011 as a basis for reopening this docket.

Q. How were the monitored fuel cost projections for 2011 developed?

A. The Company used the PROMOD security-constrained production cost model to project how its generating resources would be utilized in 2011 under MISO dispatch. The PROMOD simulation is in turn used to estimate coal, gas and fuel oil commodity costs, energy costs from Power Purchase Agreements, generator revenue and associated margin, projected Locational Marginal Price (LMP), the cost of energy purchases from MISO, and the hourly and annual net energy purchase and sale position. The LMP calculated by PROMOD is made up of marginal energy, congestion and loss components. The Company believes PROMOD provides a reasonable projection of unit utilization by MISO.

Category No. 1: Adjustments to the PROMOD Model

Q. Did the Company use the same PROMOD model which was used to project 2010 Interim Decision fuel costs?

A. Generally yes. The Company did incorporate several modifications to PROMOD to simulate recent actual market conditions. These modifications resulted in a net decrease in projected 2011 monitored fuel costs (over the levels authorized in the 2010 Interim Decision) of about $2.7M, and include:

- Translation of the 2010 PROMOD case into 2011. The Company started with the Commission-approved PROMOD run which was the basis for the 2010 Interim Decision and updated this PROMOD run with the PowerBase data which change for 2011. This modification results in a decrease of about $5.0M from monitored fuel costs established in the 2010 Interim Decision.
- The non-WE loads across MISO were increased by 1.8% from the loads in the Ventyx PowerBase data set used with PROMOD to account for load growth in the MISO footprint not accounted for in PowerBase. This change increased projected 2011 monitored fuel costs by $2.9M.
- Updates were made to non-WE wind generation across the MISO footprint which decreased projected 2011 monitored fuel costs by $0.9M.
- Non-WE unit retirements were updated in the Ventyx PowerBase file to account for recent non-WE unit retirements across the MISO footprint, which increased projected 2011 monitored fuel costs by $0.1M.
- MISO operating reserves were updated in PROMOD to better reflect actual MISO operating reserves practices, which increased projected 2011 monitored fuel costs by $0.3M.

- Forced outage factors for Oak Creek and Pleasant Prairie units were updated and made consistent with five year average Generating Availability Data System (GADS) data resulting in a decrease in projected 2011 monitored fuel costs of $1.2M.
- To reflect current operations, we changed the modeling of Presque Isle units 5 and 6 and Valley units 1 and 2 to reflect one unit at each plant being offered as economic, instead of must run, for portions of the year resulting in a decrease in projected 2011 monitored fuel costs of $3.1M.
- We updated WE unit heat rates based on most recent year of operations experience resulting in an increase in projected 2011 monitored fuel costs of $4.2M.

Q. Other than the updates you previously described, were the methods used in establishing assumptions and modeling system fuel costs similar to those methods found to be acceptable by the Commission in the past?

A. Generally yes. With one exception, we employed the same methods used by staff and approved by the Commission in the 2009 Final Decision. The one exception is that the Company projected future 2011 natural gas prices using the more-traditional 12 month NYMEX strip method (the method used and approved in the 2010 Interim Decision) rather than the method proposed by staff and approved by the Commission in the 2009 Final Decision. Other PROMOD inputs were updated to reflect the most recent data available. Some of the updates had the effect of increasing projected fuel costs but others had the effect of reducing projected fuel costs. In addition, the Company used the Commission-approved forecast of customer demand (retail and wholesale), which was included in the 2009 Final Decision. Accordingly, the net output (MWh) from the 2011 PROMOD fuel run is equal to the output incorporated in the 2009 Final Decision.

Category No.2: Increased coal costs

Q. How much of the change in projected 2011 monitored fuel costs is accounted for by increased coal costs?

A. Increased projected coal cost increases monitored fuel cost for 2011 by about $57.7M compared to the 2010 Interim Decision. Of this total, $10.0M is due to higher coal prices (FOB mine); $32.7M is due to increased transportation costs, $7.0M is due to coal inventory changes; and $8.0M is due to increased oil surcharge costs.

Q. Please describe the increase in FOB mine coal costs.

A. FOB mine coal costs increased from levels in the 2010 Interim Decision by $10M primarily driven by increased coal contract costs for Valley and Presque Isle-East, and at Elm Road. The changes at Valley and Presque Isle-East reflect escalation in coal costs observed in 2009 and 2010, the effects of which were muted in those years due to carryover of lower priced coal from 2008 and 2009 into 2010. The full impacts of the escalation across those years are now observed in coal costs projected for 2011. The FOB mine coal costs for Elm Road are projected to increase due to contract coal price increases.

Q. Now please describe the impacts of and drivers behind increased coal transportation costs.

A. Coal transportation costs increased from levels in the 2010 Interim Decision by $32.7M. The primary driver behind this increase is a change in carrier for coal delivered to Pleasant Prairie and Presque Isle–West. One of the coal transportation carriers for P4 and PI-W for 2009 and 2010 is DTE. This coal transportation contract expires in 2010, and through a process of competitive bidding, the Company selected the Union Pacific (UP) and the Burlington Northern (BN) railroads for delivery to P4 and PI-W, respectively in 2011.

Q. Please describe the impacts of changes in coal inventory between 2010 and 2011 on projected 2011 monitored fuel costs.

A. Changes in coal inventory are projected to increase 2011 monitored fuel costs by $7.0M.

Q. Please elaborate.

A. Changes in coal inventory costs for 2011 incorporate the difference in the coal costs in inventory at the start of 2010 and at the start of 2011, and reflect that higher cost coal was delivered during 2010 (inventory 2011) versus 2009 (inventory 2010).

Q. Please describe the change in projected coal transportation surcharge levels for 2011.

A. Coal transportation surcharge levels increase 2011 monitored fuel costs by $8.0M due to new or increased oil surcharge costs.

Category No. 3: Updated MISO energy market items

Q. How much of the change in projected 2010 fuel costs is accounted for by MISO energy market items?

A. MISO energy market items result in a net decrease in projected 2011 monitored fuel costs of $5.9M from the levels established in the 2010 Interim Decision.

Q. Please describe this in more detail.

A. Since PROMOD does not project all the relevant MISO charges and credits, the Company used 12 months of actual MISO charges and credit amounts for the period July 1, 2009 through June 30, 2010 for the following MISO charges and credits to establish monthly and annual amounts for 2011.

- Real Time Uninstructed Amount
- Real Time Net Inadvertent Amount
- Real Time Revenue Sufficiency First Pass Uplift

- Financial Bilateral Congestion Amount
- Financial Transmission Rights (FTR) and Auction Revenue Rights (ARR)
- Financial Bilateral Transaction marginal losses
- Real-Time Distribution of Loss Amounts
- Day-Ahead Revenue Sufficiency Guarantee (RSG) Make Whole credits
- Day Ahead RSG Distribution Amount, and
- Real Time Revenue Neutrality Uplift.

In addition, the sale of Edison Sault Electric eliminates a portion of Wisconsin Electric's total company MISO charges. The use of updated actual MISO charge and credit amounts for these MISO charge types results in a $5.3M decrease in projected 2011 monitored fuel costs from amounts included in the 2010 Interim Decision.

Q. What other changes in MISO charge types have occurred since the 2010 Interim Decision?

A. Based on recent actual MISO ASM revenues, ASM revenues are projected to decrease by $0.6M from levels in the 2010 Interim Decision, which increases projected 2011 monitored fuel costs by that amount. In addition, payments to other Wisconsin utilities under the WUMS socialized congestion and loss agreement terminated in 2010 and, as such, are not part of 2011 monitored fuel costs, decreasing 2011 monitored fuel costs by $1.2M.

Category No. 4: Updated Resource Supply Plan

Q. How will the updated resource supply plan for 2011 affect monitored fuel costs?

A. The changes in the resource supply plan for 2011 compared to the 2010 Interim Decision will impact monitored fuel costs in two ways: (1) through changes in the cost of supplying energy to the MISO and the corresponding contribution of net generator margin (revenue from sales into MISO minus production costs) to reduce monitored fuel costs; and (2) through the sale of capacity above the level required by the PSCW and MISO Module E. The net impacts of energy sales to MISO and net generator margin are projected to decrease projected 2011 monitored fuel costs by $5.3M. The details within this category are summarized below:

- The Point Beach Power Purchase Agreement (PPA) between NextEra and Wisconsin Electric has an increase in energy costs ($/MWh) for 2011. The net impact of this change in PPA costs increases projected 2011 monitored fuel costs by about $10.5M.
- NextEra has been providing replacement energy during planned and forced outages in accordance with the PPA. Inclusion of this replacement energy for the planned and forced outages during 2011 increases projected 2011 monitored fuel costs by $2.1M.
- The planned capacity uprates for Point Beach Unit 1 and 2 are currently scheduled for 2011. Unit 2 will have its uprated capacity (80MW) available to deliver energy on or about June 1, 2011, and Unit 1 will have its upgraded capacity (80MW) available on or about December 15, 2011. While the Company has not yet made a final decision on whether it will take all or a portion of the upgraded capacity and associated energy, for the purpose of this filing, the Company has assumed that the increased PPA costs associated with the increased energy will flow to 2011 monitored fuel costs. Accordingly, this additional energy from Point Beach is projected to increase 2011 monitored fuel costs by $6.2M. (It should be noted that all PPA-related costs for Point Beach go to monitored fuel. The value of the PB units under the PPA includes not only energy, but capacity and ancillary services.)
- The sale of the Company’s share of Edgewater Unit 5 to Alliant Energy is expected to close by the end-of-2010. Therefore, the Company will not have this generating resource

- A large cost savings ($24.0M) in 2011 compared to 2010 is due to the operation of Elm Road Unit 2 for all of 2011. The 2010 Interim Decision assumed a Unit 2 in-service date of September 29, 2010 allowing only about three months of operation in 2010. The cost savings were reduced by $1.8M due to an increase in the projected forced outage rate for Unit 2 from 10% to 20%, based on the Company's experience with the first year of operation of Elm Road Unit 1. The net impact of these Elm Road changes is to reduce projected 2011 monitored fuel costs by about $22.2M.
- The Company is negotiating the purchase of about 300,000 MWh of wind-generated energy for 2011 and beyond as part of its effort to comply with the Wisconsin Renewable Portfolio Standards (RPS). Based on the difference between PPA costs and projected LMP at the generator nodes where energy will be injected, the cost of this additional wind energy is projected to increase 2011 monitored fuel costs. Customer-owned renewable energy will be purchased at the COGS rate in 2011 resulting in a projected decrease in 2011 monitored fuel costs. The combined effect of these two renewables purchase changes is a decrease in projected 2011 monitored fuel costs of about $1.9M.

Q. What impact will the sale of capacity have on 2011 monitored fuel costs?

A. The Company projects that 2011 monitored fuel costs will be reduced by $7.7M due to the sale of capacity.

Category No. 5: Impacts of Transmission Congestion

Q. How much of the change in projected 2011 fuel costs is accounted for by updated projections of congestion on the transmission system?

A. This category results in an increase of about $19.5M from the levels established in the 2010 Interim Decision.

Q. Please describe this in more detail.

A. The Company is experiencing increased congestion of the transmission system at locations south of Pleasant Prairie and south of Lake Michigan, which results in the depression of prices (LMPs) at Pleasant Prairie, Oak Creek and Elm Road and corresponding reduced utilization of these facilities, particularly during lower priced, off-peak periods. See Exhibit 1.1 (JEK). The impacts of these two phenomena are to reduce generator margin and thereby increase monitored fuel costs. This congestion was initially observed by the Company in late-2008, and has been steadily increasing with time. The Company has been working with MISO, PJM and other stakeholders in studying possible solutions to the congestion and with ATC in similar studies. (Possible "quicker to implement" solutions are being identified in these studies and are likely to be implemented in several years, with "longer to implement" solutions taking perhaps 5 or more years to license and install.)

Q. How did you model the increased transmission system congestion?

A. Transmission limits in PROMOD are initially populated with data from Ventyx (the PROMOD vendor). Next, we added transmission limits used by MISO in their PROMOD modeling. About 300 event file items (new lines, revised flowgate limits and other transmission topology changes) were added. We benchmarked the change by comparing our PROMOD constrained flowgate list with actual constrained flowgates and MISO's

PROMOD constrained flowgate list (Exhibit 1.2 (JEK)). Our event file captured 11 of the top 20 actual binding constraints, on par with MISO's event file performance.

Category No. 6: Other Changes in Monitored Fuel Costs

Q. How much of the change in projected 2011 fuel costs is accounted for by other changes in monitored fuel costs?

A. Other changes to monitored fuel costs amount to a decrease of $17.8M in monitored fuel costs from those levels established in the 2010 Interim Decision. This category includes the following items:

- Differences in 2011 planned outage schedule compared to 2010 – decrease of $6.1M,
- Updated August 27, 2010 NYMEX forecasts for 2011 gas and oil – decrease of $6.1M,
- Miscellaneous changes – decrease of $2.5M and
- Risk Management costs – decrease of $3.1M

Q. Please describe the miscellaneous changes which, altogether, decrease 2011 monitored fuel costs by $2.5 million compared to the 2010 Interim Decision amount.

A. Changes to miscellaneous items include:

- The Elm Road and Port Washington generating facilities use auxiliary boilers for unit startup, building heating, and a number of other applications. The 2010 Interim Decision included projections of auxiliary boiler operation and corresponding gas use and cost. Based on updated projections of unit operation and gas prices at these facilities, 2011 monitored fuel costs are projected to decrease by $0.1M.
- The 2010 Interim Decision included $0.5M for a test burn of alternate coal at the Valley Power Plant. Since the Company has no plans to conduct additional test burns during 2011, monitored fuel costs will decrease by that amount.

- Increased PJM make-whole and ARR revenues in 2011 are projected to decrease 2011 monitored costs by $1.9M.

Q. Please discuss the integrated risk management plan and its expected impact on 2011 monitored fuel costs.

A. The Company has an integrated risk management program approved by the Commission on December 23, 2008. The plan includes risk management efforts for hedging oil surcharge costs associated with coal transportation, electric purchases and sales and natural gas costs. Transaction costs associated with hedging are monitored fuel costs. The 2010 Interim Decision included about $4.5M of hedging-related transaction costs. Based on the updated levels of gas purchases, rail transportation costs and electric sales contained in this filing, the Company projects its 2011 hedging-related transaction costs at about $1.4M, a decrease of about $3.1M compared to the costs included in the 2010 Interim Decision.

Q. Does this complete your testimony?

A. Yes.