ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF A FUEL COST CHARGE AND CUSTOMER CREDIT ADJUSTMENT TO BE APPLICABLE IN THE MONTHS OF AUGUST, SEPTEMBER, AND OCTOBER, 2009 PURSUANT TO IC 8-1-2-42 AND CAUSE NO. 41746.	)	CAUSE NO. 38706 FAC 83 APPROVED: JUL 30 2009

BY THE COMMISSION:
David E. Ziegner, Commissioner
Aaron A. Schmoll, Administrative Law Judge

On May 6, 2009, Northern Indiana Public Service Company ("NIPSCO" or "Petitioner") filed its petition for Commission approval of a fuel cost adjustment to be applicable and made effective for bills rendered by Petitioner during the billing months of August, September and October, 2009. Petitioner also prefiled its direct testimony and exhibits in support of its petition on May 6, 2009. NIPSCO Industrial Group ("NIPSCO-IG") and the City of Hammond, Indiana ("Hammond") filed Petitions to Intervene on May 12, 2009, both of which were granted. On June 10, 2009, the Office of Utility Consumer Counselor ("OUCC") filed its report in this Cause and the Direct Testimony of Gregory T. Guerrettaz (Public's Exhibit No. 1)[1] and Michael D. Eckert (Public's Exhibit No. 2).

Pursuant to public notice duly given and published as required by law, proof of which was incorporated into the record by reference and placed in the Commission's official file, a public hearing in this Cause was held on July 16, 2009, at 1:30 p.m., in the National City Center, Room 222, 101 W. Washington Street, Indianapolis, Indiana. At the hearing Petitioner, the OUCC, NIPSCO-IG and Hammond appeared by counsel. Petitioner and OUCC offered their respective prefiled testimony and exhibits and the OUCC offered its response to the Commission's July 14, 2009 docket entry, which were admitted into evidence without objection. No other party or members of the general public appeared.

Based upon the applicable law and the evidence of record, the Commission now finds:

1. **Commission Jurisdiction and Notice.** Proper notice of the hearing in this Cause was given as required by law. Petitioner is a public utility corporation incorporated under the laws of the State of Indiana, operating electric utility properties in northern Indiana and is subject to the jurisdiction of this Commission as provided in the Public Service Commission Act, as amended, IC 8-1-2. Thus, the Commission has jurisdiction over NIPSCO and the subject matter of this Cause.

2. **Petitioner's Characteristics.** Petitioner has its principal office at 801 East 86th Avenue, Merrillville, Indian[a]. Petitioner is engaged in rendering electric public utility service in

[1] On June 11, 2009, the OUCC filed substitute prefiled testimony and exhibits of Gregory T. Guerrettaz (to include inadvertently omitted pages)

the State of Indiana and owns, operates, manages and controls, among other things, plants and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such service to the public.

3. **Available Data on Actual Fuel Costs.** The Petitioner's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity in Petitioner's last base rate case order, approved, July 15, 1987, in Cause No. 38045, was $0.022556 per kWh (Petitioner's Exhibit B, Schedule. 1, Ln. 28). Petitioner's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity for the months of January, February and March, 2009 averaged $0.029156 per kWh (Petitioner's Exhibit B, Schedule 5, p. 4, Ln. 27).

4. **Requested Fuel Cost Charge.** Petitioner seeks to change its fuel cost adjustment charge from the current charge of $0.007163 per kWh (Petitioner's Exhibit 1-C, Ln. 6) to a charge of $0.005682 per kWh (Petitioner's Exhibit B, Schedule 1, Ln. 30) for bills rendered in August, September and October, 2009 billing months. The requested fuel cost adjustment charge includes a variance of ($6,448,441) (Petitioner's Exhibit B, Schedule 1, Ln. 25) that was over collected during January, February and March, 2009. Petitioner's estimated monthly average cost of fuel to be recovered in this proceeding for the period August, September and October, 2009, is $42,812,937 (Petitioner's Exhibit B, Schedule 1, Ln. 23), and its estimated monthly average sales for that period are 1,444,462 MWh. (Petitioner's Exhibit B, Schedule 1, Ln. 11).

5. **Statutory Requirements.** Ind. Code § 8-1-2-42(d) states that this Commission shall grant a fuel cost adjustment charge if it finds that:

(1) The electric utility has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible;

(2) The actual increases in fuel cost through the latest month for which actual fuel costs are available since the last order of the Commission approving basic rates and charges of the electric utility have not been offset by actual decreases in other operating expenses;

(3) The fuel adjustment charge applied for will not result in the electric utility earning a return in excess of the return authorized by the Commission in the last proceeding in which the basic rates and charges of the electric utility were approved. However, subject to Ind. Code § 8-1-2-42.3, if the fuel charge applied for will result in the electric utility earning a return in excess of the return authorized by the Commission in the last proceeding in which basic rates and charges of the electric utility were approved, the fuel charge applied for will be reduced to the point where no such excess of return will be earned.

6. **Fuel Costs and Operating Expenses.** Petitioner's Exhibit 2-A, page 1, shows that fuel costs for the twelve months ending March 31, 2009, increased $187,495,236 (Petitioner's Exhibit 2-A, p. 1, Ln. 22) from the pro forma level established in Petitioner's last base rate case, Cause No. 38045. Petitioner's Exhibit 2-A also shows that Petitioner's total operating expenses, excluding fuel in the twelve months ended March 31, 2009, exceeded by $220,245,738 (Petitioner's Exhibit 2-A, p. 1, Ln. 24) the pro forma level of other operating expenses determined pursuant to this Commission's Order in Cause No. 38045. The Commission finds that Petitioner's fuel costs have increased since its last general rate order and

that the actual increases in fuel costs have not been offset by actual decreases in other operating expenses.

7. **Efforts to Acquire Fuel and Generate or Purchase Power to Provide Electricity at the Lowest Reasonable Cost.** Petitioner's witnesses described Petitioner's efforts to purchase fuel and generate and purchase power at the lowest cost reasonably possible. Witness Strnatka testified that Petitioner's primary fuel for generation of electric energy is coal (90.57% for the three months ended March 31, 2009). (Petitioner's Exhibit 4, p. 1).

Witness Hasselbring testified concerning an outage at NIPSCO's Michigan City Unit 12 ("Unit 12"). Mr. Hasselbring stated that the coal ramp that brings coal into the main building for Unit 12 experienced a fire on January 8, 2009. Due to the damage from the fire, the coal conveyor and its structure had to be completely replaced. He stated that during the period of the structure rebuild, the station performed the annual planned maintenance outage on Unit 12 that was originally scheduled for later in the year. When the unit was not in the outage it was available to operate at full load on gas. Mr. Hasselbring stated that MISO did not call for the unit to run on gas during this time period. He stated that Unit 12 returned to operation on coal on April 18, 2009. OUCC's witness Eckert stated while the OUCC has reviewed NIPSCO's responses to data requests relating to Unit 12, the OUCC believes there are still some additional issues that need to be addressed. He stated that the OUCC is in the process of issuing some additional data requests to address these concerns. Mr. Eckert recommended that Petitioner's FAC rates be made interim, subject to refunding, pending resolution of these issues.

On July 14, 2009, the Commission issued a docket entry requesting the OUCC to provide additional information relating to the Unit 12 outage. At the hearing, the parties proposed that additional information would be provided and the issue resolved in either the FAC 80 subdocket or in FAC 84. Based on the evidence, but subject to further consideration in the subdocket established in FAC 80 and further evidence, if any, related to the Unit 12 outage, we find that Petitioner has made every reasonable effort to acquire fuel and generate or purchase power so as to provide electricity to its retail customers in a reliable manner and at the lowest fuel cost reasonably possible, as hereinafter discussed.

8. **Midwest ISO Day 2 Energy Costs.** NIPSCO took into account in its forecast for this case the operational changes associated with the Midwest ISO Day 2 energy market, in accordance with the Commission's Orders in Cause Nos. 42685, 42962, 43471; and its FAC proceeding from FAC 68,. In Cause No. 42685, Petitioner was authorized to treat certain defined Midwest ISO Day 2 market costs as a cost of fuel for purposes of the FAC process. In Cause Nos. 42962 and 43471, Petitioner was authorized to recover in FAC proceedings its Revenue Sufficiency Guarantee ("RSG") costs incurred after December 8, 2005. In the evidence submitted in support of its requested relief in this proceeding, Petitioner followed our orders in both Cause No. 42685 and Cause No. 43471. The Petitioner included in the FAC factor $7,272,154 as the total "MISO Components of Fuel Cost" for the months of January, February and March, 2009. (Petitioner's Exhibit B, Schedule 5, p. 4, Ln. 19).

9. **Changes in Charge Types as a Result of the Start of the Ancillary Services Market ("ASM").** In this proceeding, Mr. Crum stated that NIPSCO is requesting recovery of certain costs resulting from participation in the new Midwest ISO Energy and Operating Reserves Market ("MISO EOR") that includes ancillary services, which began operation on January 6, 2009. He stated that NIPSCO has incurred new types of charges resulting from the MISO EOR which are reported for the first time in this proceeding. Mr. Crum testified that in

compliance with the Phase I Order in Cause No. 43426 ("Phase I Order"), NIPSCO is currently deferring the following new charge types related to the MISO EOR:

- Day Ahead Regulation Amount
- Day Ahead Spinning Reserve Amount
- Day Ahead Supplemental Reserve Amount
- Contingency Reserve Deployment Failure Charge Amount
- Real Time Excessive Deficient Energy Deployment Charge Amount
- Real Time Regulation Amount
- Regulation Cost Distribution Amount
- Real Time Spinning Reserve Amount
- Spinning Reserve Cost Distribution Amount
- Real Time Supplemental Reserve Amount
- Supplemental Reserve Cost Distribution Amount

He stated that the following charge types are incorporated into NIPSCO's calculation of Delta LMP included in MISO Components of Fuel Cost shown on Schedule 6 Line 1:

- Excessive Energy Amount
- Non-Excessive Energy Amount
- Net Regulation Adjustment.

Mr. Crum stated that each of these new charge types was described in Joint Petitioner's Exhibit 7 in Phase II of Cause No. 43426. Final cost recovery determination of these charge types would be made by the Commission in its Phase II Order. Mr. Crum testified that in accordance with the Phase I Order, NIPSCO was requesting authority to treat for ratemaking purposes the new Non-Excessive Energy Amount and the new Excessive Energy Amount charge types in the same manner as the existing Real Time Asset Energy Amount (for generation), the existing Real Time Uninstructed Deviation Amount, and the Real Time Uninstructed Deviation Credit (collectively, "UD") are treated today by NIPSCO, subject to refund pending a final determination by the Commission in Phase II of Cause No. 43426. He stated that these two new charge types effectively replace and have similar cost causation characteristics as these three existing charge types and therefore should be treated in the same manner. Mr. Crum stated that the existing Real Time Asset Energy Amount is the means for compensating generators for providing generation in the real time market, with the UD amounts providing for real time deviations from Midwest ISO dispatch signals. He stated that if the two new replacement charge types implemented under MISO EOR were included in the net deferral amount, the FAC rate would no longer reflect components of the cost of generating energy which are currently being incurred and recovered by NIPSCO as delta LMP for native load.

OUCC's witness Eckert did not contest NIPSCO's treatment of any of the new charge types, except for the Net Regulation Adjustment, which is discussed hereinafter.

Mr. Crum stated that the following charges types have been modified as a result of the MISO EOR:

- Day Ahead Market Administration Amount (Schedule 17)
- Day Ahead Revenue Sufficiency Guarantee ("RSG") Distribution Amount
- Day Ahead RSG Make Whole Payment Amount

- Real Time Market Administration Amount (Schedule 17)
- Real Time RSG First Pass Distribution Amount
- Real Time RSG Make Whole Payment Amount

Mr. Crum testified that these items identified as modified would continue to be treated for ratemaking purposes as they are today by NIPSCO until a final determination by the Commission in Phase II of Cause No 43426. He stated that if the costs from a charge type are currently recovered through NIPSCO's FAC then amounts from that charge type should continue to be recovered through the FAC. If the costs from a charge type are currently deferred then amounts from that charge type should continue to be deferred. Mr. Crum stated that this treatment is proposed because the Midwest ISO makes no distinction or allocation between energy and ancillary services for the modified charge types.

OUCC's witness Eckert agreed that NIPSCO followed the treatment ordered by the Commission in the Phase I Order for modified charge types.

While the Commission recognizes that an Order has now been entered in Phase II of Cause No. 43426, based upon the evidence presented, the Commission finds that NIPSCO's deferral of new and modified charge types (except for Net Regulation, which is discussed hereinafter) is consistent with the Commission's Phase I Order, and should be approved. NIPSCO will address the impact of Phase II in its next FAC filing.

10. **Net Regulation Adjustment Charge Type.** Mr. Crum explained that in the Phase I Order the Commission authorized deferral of the new Net Regulation Adjustment charge type. However, NIPSCO subsequently recognized that this charge type is closely related to Non-Excessive Energy as it represents the difference (charge or credit) between the generator's offer price and the LMP for megawatts generated in response to deployed regulation instructions. OUCC's witness Eckert recommended the Commission require NIPSCO to follow the Commission's order regarding treatment of ASM charges and deny NIPSCO's request to recover the Net Regulation Adjustment Amount through the FAC.

With respect to the Net Regulation Adjustment charge type, the Commission is not persuaded that NIPSCO's evidence supports a modification in the treatment of that charge type authorized in our Phase I Order. Accordingly, we find that NIPSCO's proposed treatment should not be approved and that this charge type should be deferred as set forth in the Commission's Phase I Order. In light of the fact that this finding does not alter the proposed fuel factor, NIPSCO should apply the necessary correcting adjustments in its next FAC filing.

11. **Estimation of Fuel Cost.** The Petitioner estimates that its prospective total average fuel costs for the billing months of August, September and October, 2009, will be $42,812,937 (Petitioner's Exhibit B, Schedule 1, Ln. 23) on a monthly basis. Petitioner previously made the following forecasts of its fuel cost in January, February and March, 2009 and incurred the following actual costs, resulting in a percent error calculated as follows:

Month	Estimated Fuel Cost	Actual Fuel Cost	Percent Estimate Over (Under) Actual
January	$0.033166/kWh	$0.030202/kWh	9.81%
February	$0.033478/kWh	$0.029775/kWh	12.44%
March	$0.032629/kWh	$0.027307/kWh	19.49%
Weighted Average Error (%)			13.48%

Petitioners' Exhibit B, Schedule 5, pp. 1-3, Lns. 27-28; Petitioner's Exhibit B, Schedule 5, p. 4, Ln. 28.

OUCC Witness Gregory T. Guerrettaz testified that nothing had come to his attention that would indicate that the projections used by NIPSCO for fuel costs and sales of power were unreasonable. Public's Exhibit No. 1, p. 7. OUCC's witness Eckert stated that Sugar Creek is now included in the Midwest ISO system and, therefore, is included in the estimated period. Public's Exhibit No. 2, p. 4.

Based on the evidence, we find that NIPSCO has made every reasonable effort to project its fuel related costs for August, September and October, 2009.

12. **Return Earned.** Petitioner's Exhibit 2, containing Exhibit 2-A, demonstrates that for the twelve months ended March 31, 2009, Petitioner earned a jurisdictional return of $165,072,220 (Petitioner's Exhibit 2-A, p. 1, Ln. 21c, Col. F), a 6.63% rate of return (Petitioner's Exhibit 2-B, Ln. 9) on its jurisdictional rate base from Cause No. 38045. This amount included $20,388,237 (Petitioner's Exhibit 2-A, p. lB, Ln. 1) of opportunity off-system sales made from internally generated power, offset by fuel, purchased power costs, supporting variable costs and taxes for a net profit of $4,230,582, (Petitioner's Exhibit 2-A, p. l, Ln. 21b) in accord with the settlement agreement, referred to as the "August Agreement," approved by the Commission in Cause No. 42824 Order, Ordering Paragraph 1 (Aug. 23, 2006). As shown in Petitioner's Exhibit 2-A, the jurisdictional return authorized in Cause No. 38045, beginning in 1992 and thereafter, and adjusted for the Environmental Cost Recovery Mechanism return authorized in Cause No. 42150 ECR 12, pursuant to Ind. Code § 8-1-2-6.6 and 6.8, was $242,709,024 (Petitioner's Exhibit 2-A, p. 1, Ln. 21c, Col. B). Therefore, during the 12-month period ending March 31, 2009, NIPSCO did not earn a return more than that authorized in its last base rate case, as appropriately adjusted.

13. **Earnings Subject to Sharing.** Pursuant to the Commission's September 23, 2002 Order in Cause No. 41746 and the settling parties' acceptance of that Order, NIPSCO must share the over-earnings reported in each FAC. Petitioner's Exhibit 2-A reflects that for the 12-month period ended March 31, 2009, Petitioner has no such over-earnings.

14. **Fuel Cost Adjustment Factor.** As we have set forth herein, Petitioner has, subject to further consideration in the subdocket established in FAC 80, met the tests of Ind. Code § 8-1-2-42(d) for establishing a revised fuel cost charge. Petitioner's evidence presented a variance factor of $(0.001488) per kWh (Petitioner's Exhibit B, Schedule 1, Ln. 26), to be added to the estimated cost of fuel for the billing months of August, September and October, 2009, in the amount of $0.029639 per kWh (Petitioner's Exhibit B, Schedule 1, Ln. 24), resulting in a fuel cost charge factor of $0.005682 per kWh (Petitioner's Exhibit B, Schedule 1, Ln. 30), after

subtracting from that cost the cost of fuel in NIPSCO's base rates and adjusting for applicable taxes. The average residential customer using 1,000 kwh per month will experience an overall decrease of $1.48 on his or her electric bill from the currently approved factor.

15. **Customer Credit Adjustment Factor.** Pursuant to our September 23, 2002 order in Cause No. 41746, Petitioner has set forth evidence of a Customer Credit Adjustment Factor percentage of 5.3874 (Petitioner's Exhibit D, p. 1, Ln. 10) to be applicable during the billing months of August, September and October, 2009. Petitioner's evidence showed the factor is calculated in accordance with the methodology prescribed in the September 23, 2002 order in Cause No. 41746.

16. **OUCC Report.** Mr. Guerrettaz testified: (1) NIPSCO has calculated the fuel cost element of the proposed fuel cost adjustment in conformity with the requirements of Ind. Code § 8-1-2-42; (2) NIPSCO has calculated a variance for the quarter ending September, 2009 in conformity with the requirement of Ind. Code § 8-1-2-42; (3) the level of operating income for the twelve month period ending March 31, 2009 is less than the level approved in NIPSCO's last rate case, Cause No. 38045, adjusted to reflect our order in Cause No. 42150 ECR 12; and (4) the fuel cost adjustment for the quarter ending March 31, 2009 has been properly applied.

17. **Uninstructed Deviation Penalties.** In Cause No. 38706-FAC74, Petitioner presented a Settlement Agreement regarding uninstructed deviation charges ("UD Settlement"). In the Commission's Order in FAC71-S1, the Commission found that uninstructed deviation penalties are a reasonable cost of generating power in the Midwest ISO market and may be properly included as a cost of fuel in FAC proceedings, unless it is demonstrated that the utility failed to use Good Utility Operating Practice. The Commission further found that in any month that uninstructed deviation charges exceed uninstructed deviation revenue, Petitioner must provide an explanation as to why and quantify the impact on the FAC factor. Petitioner's Witness Crum stated that with the start of the ASM uninstructed deviation charges no longer exist and that NIPSCO is not seeking recovery for the first five operating days of January prior to the start of ASM.

18. **Purchased Power Costs Above Monthly Standard.** Mr. Crum described the Revised Benchmark that applies to Petitioner's purchased power transactions on and after October 1, 2007. He stated that on January 30, 2008, a final order was issued in Cause No. 38706-FAC-71S1, instituting a three tier Benchmark. Originally Tier 1 of the Benchmark utilized the costs of a Combined Cycle Gas Turbine ("CCGT") to establish the benchmark for determining the level of purchased power costs to be recovered by Petitioner. Effective December 1, 2008 Sugar Creek was dispatched into the Midwest ISO and Tier 1 was eliminated. When Tier 1 of the Benchmark was eliminated on December 1, 2008, Tier 2 of the Revised Benchmark became applicable to the first 500 MW of power purchases used to serve FAC load and became Tier 1. The current Tier 1 of the Revised Benchmark utilizes the costs of a Combustion Turbine ("CT") for determining the level of purchased power recovery. The current Tier 1 formula is almost the same as the recovery formula previously approved for Petitioner and other Indiana utilities using a benchmark recovery mechanism. Current Tier 2 permits, absent an act of God or a force majeure situation, Petitioner to recover 85% of its purchased power costs in excess of 500 MW. The applicable purchased power benchmark computed for January, 2009 is $80.00/MWh for the first 500; for February, 2009 is $63.75/MWh for the first 500 MWs; and for March, 2009 is $52.50/MWh for the first 500 MWs. Petitioner did not seek recovery of any purchased power costs in excess of the computed standard.

OUCC Witness Eckert confirmed Petitioner's purchased power benchmark calculations and confirmed $751,726 of purchase power as being non-recoverable in compliance with the Revised Benchmark.

Mr. Eckert stated that in FAC80, the parties agreed to move issues regarding NIPSCO's requested recovery of hedging losses, NIPSCO's hedging policy, NIPSCO's stacking of power purchases between native load and off-system sales, and NIPSCO's calculation of purchased power costs under the Revised Benchmark to a sub-docket in Cause No. 38706 FAC 80 S1 ("FAC 80 Subdocket"). Mr. Eckert stated that these same concerns are concerns in this Cause. Mr. Eckert recommended that Petitioner's FAC rates be made interim, subject to refund, pending the final outcome of the FAC 80 Subdocket.

19. **Interim Rates.** Because we are unable to determine whether Petitioner will earn an excess return while this Order is in effect and because of the uncertain outcome of the FAC 80 Subdocket as discussed in Finding No. 18 above and questions regarding the outage at Michigan City Unit 12, as referenced in Finding No. 7 above, the Commission finds that the rates approved herein should be interim rates, subject to refund.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. Petitioner's requested fuel cost charge to be applicable to bills rendered in the months of August, September and October, 2009, as set forth in Finding No. 14 above is hereby approved on an interim basis subject to refund as set out in Finding No. 19 above.

2. Petitioner's requested Customer Credit Adjustment Factor percentage to be applicable to bills rendered in the months of August, September and October, 2009, as set forth in Finding No. 15 above, is hereby approved.

3. Petitioner shall file with the Electricity Division of the Commission, prior to placing in effect the fuel cost adjustments herein approved, an amendment to its rate schedule with reasonable reference therein reflecting that such charges are applicable to the rate schedules reflected on the amendment.

4. This Order shall be effective on and after the date of its approval.

HARDY, ATTERHOLT, LANDIS AND ZIEGNER CONCUR; GOLC ABSENT:

APPROVED: JUL 30 2009

I hereby certify that the above is a true and correct copy of the Order as approved.

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission