ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF ANNUAL DEMAND, TAKE-OR-PAY, TRANSITION AND STORAGE AND TRANSMISSION COSTS TO BE APPLICABLE IN THE TWELVE-MONTH PERIOD, BEGINNING NOVEMBER 1, 2009	)	**CAUSE NO. 41338 GCA 11** **FINAL ORDER** **APPROVED:** MAR 24 2010

BY THE COMMISSION:
James D. Atterholt, Commissioner
Lorraine Hitz-Bradley, Administrative Law Judge

On August 27, 2009, Northern Indiana Public Service Company ("Petitioner" or "NIPSCO"), filed its verified Petition in this Cause for approval of the annual demand, storage and transmission cost of NIPSCO's rates, to be applicable during the twelve-month period beginning November 1, 2009. The filing was made in accordance with the Commission's August 11, 1999 Order in Cause No. 41338. Also on August 27, 2009, Petitioner filed its case-in-chief consisting of the testimony of Katherine A. Cherven and Karl E. Stanley.

Petitions to Intervene were filed by the NIPSCO Industrial Group ("Industrial Group") and the City of Hammond, Indiana ("Hammond") on September 1 and October 6, 2009, respectively. The *Petition to Intervene* of the Industrial Group was granted on September 9, 2009 and the Hammond *Petition to Intervene* was granted on October 14, 2009.

Pursuant to notice published as required by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, a Prehearing Conference and Preliminary Hearing was held in this Cause on October 7, 2009 at 1:30 P.M. EDT in Room 224 of the National City Center, 101 W. Washington Street, Indianapolis, Indiana. A Prehearing Conference Order was issued on October 28, 2009.

On October 19, 2009, Petitioner filed its *Unopposed Motion to Make Rates Effective Subject to Refund* ("Motion"). In its *Motion*, Petitioner proposed that the rates as contained in its August 27, 2009 Petition be made effective, on an interim basis, subject to refund. The *Motion* stated that the estimated annualized demand costs represent a $488,200 increase or 0.6% over the costs that were in effect pursuant to the Commission's Interim Order issued on November 20, 2008 in Cause No. 41338 GCA10. The *Motion* also stated that the OUCC, the Industrial Group, and Hammond had no objection to the *Motion*. On December 2, 2009, the Commission issued an *Interim Order* granting Petitioner's *Motion*.

Also on October 19, 2009, Petitioner filed a motion seeking confidential treatment of Exhibit 2G, which contains information about peak sales day requirements, and storage and transportation services and rates. The motion was supported by an affidavit from Mr. Karl E. Stanley. The motion was granted in a Docket Entry dated November 3, 2009, and on November 6, 2009 Petitioner filed its *Notice of Confidential Filing*.

On December 15, 2009, the OUCC submitted the testimony of Jerome D. Mierzwa. On January 26, 2010, Petitioner filed the rebuttal testimony of Ms. Cherven.

Pursuant to notice published as required by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, an evidentiary hearing was held in this Cause on February 9, 2010 at 9:30 a.m. EST in Room 222 of the National City Center, 101 W. Washington Street, Indianapolis, Indiana. Petitioner, the OUCC, the Industrial Group and Hammond all appeared at the hearing and the testimony and exhibits of Petitioner and the OUCC were presented without objection. No member of the ratepaying public appeared at the hearings. Based upon the applicable law and evidence presented herein, the Commission now finds as follows.

1. <u>Notice and Jurisdiction</u>. Petitioner owns and operates a public utility which is subject to the jurisdiction of this Commission as provided in the Public Service Commission Act, as amended.

The Commission's August 11, 1999 order in Cause No. 41338 approved a redesigned GCA mechanism consisting of two parts: a monthly commodity filing and an annual demand charge filing. Under the redesigned mechanism, Petitioner has been making a monthly commodity filing to determine the gas commodity component of the GCA factor for a calendar month, with twelve monthly filings being made each year. Petitioner began making these monthly commodity filings on September 1, 1999. Also, under the redesigned GCA mechanism as approved by the Commission, Petitioner is required to make an annual filing three working days prior to September 1 of each year to determine the demand component of its gas costs for the twelve months to be effective on November 1 of the year in which the annual filing is made. Petitioner's August 27, 2009 Petition represents the eleventh annual filing pursuant to the redesigned GCA mechanism as approved by the August 11, 1999 Order. However, pursuant to the Commission's August 26, 2009 order in Cause No. 43629, Petitioner will not be making any future annual filings under the redesigned GCA mechanism, but will instead return to quarterly GCA filings, to be filed as sub-dockets to Cause No. 43629. This Commission has jurisdiction over the parties and the subject matter of this Cause.

2. <u>Petitioner's Characteristics</u>. Petitioner is engaged in rendering natural gas utility service to the public within the State of Indiana and owns, operates, manages and controls plant and equipment used for distribution and furnishing such service.

3. <u>Petitioner's Direct Evidence</u>. Mr. Stanley, Executive Director, Energy Supply and Trading for Petitioner, explained the general nature of Petitioner's gas supply policy. Mr. Stanley stated that Petitioner's gas supply practice has been and continues to be to secure reliable firm gas supply at the lowest cost reasonably possible, with the objective of meeting the Company's current and anticipated customer requirements. Petitioner meets this objective by managing a balanced and diversified gas supply portfolio comprised of commodity, transportation and storage resources. The commodity portfolio is balanced with a combination of fixed-price (physical and financial) and market-based purchases. The commodity portfolio diversification is achieved by acquiring gas from a number of suppliers through a competitive bidding process and using a variety of pricing structures from multiple locations. These gas supplies are delivered to Petitioner through multiple long-term firm transportation arrangements with several different interstate gas pipelines providing access to multiple supply basins. Petitioner also has several long-term firm contractual storage services as well as on-system storage capability to meet its gas customers' requirements. The storage portfolio contains a variety of storage service types in multiple locations in the market area and producing regions.

Mr. Stanley described Petitioner's sources of gas supply used to serve the requirements of its gas customers. During the twelve-month recovery period beginning November 1, 2009, the Company will purchase supply under firm arrangements on both a term and spot market basis. To achieve diversity of supply, Petitioner has contracted with several pipelines permitting access to multiple supply basins. Petitioner has long-term firm transportation contracts with Natural Gas Pipeline Company of America ("Natural"), Panhandle Eastern Pipe Line Company ("Panhandle"), Trunkline Gas Company ("Trunkline"), ANR Pipeline Company ("ANR"), Vector Pipeline ("Vector") and Northern Border Pipeline ("Border"). The long-term, firm, long-haul transportation contracts with Natural, Panhandle, Trunkline, and ANR have an aggregate Maximum Daily Quantity ("MDQ") during the peak season of 458,151 Dth and an off-peak MDQ of 340,174 Dth. Generally speaking, the winter season is defined as the peak season, and the summer season is defined as the off-peak season.

Mr. Stanley testified that firm storage service contracts with Natural, Panhandle, ANR, Moss Bluff Hub Partners, L.P. ("Moss Bluff"), Kinder Morgan Texas Pipeline, L.P. ("KMTP"), ENSTOR Operating Company ("Katy"), Washington 10 Storage Corporation ("Washington 10") and Egan Hub Partners, L.P. ("Egan") provide an annual storage capability of 31,745,601 Dth, with maximum daily withdrawal capability of 639,083 Dth to meet winter peaks. These contracted supplies are reinforced with Company-owned underground storage with a capacity of 6,750,000 Dth and LNG storage with a capacity of 4,000,000 Dth, both of which are located within Petitioner's gas service territory.

Mr. Stanley described the competitive bidding process used by Petitioner. Twice a year, Petitioner conducts a Request for Proposal ("RFP") process to secure bids for term, firm, gas supplies. Typically, as a result of this bidding process, Petitioner will award contracts to commodity suppliers for a significant portion of Petitioner's projected gas supply needs. One RFP is prepared for the peak season and a second is prepared for the off-peak season. The RFP process is used to contract for firm gas supply at specified points, under known pricing methods, for a defined period of time. The RFP process includes a determination of the volume of gas that can be received by Petitioner each day, month and/or season within minimum and maximum system constraints. This evaluation takes into account projected customer demand requirements in addition to storage and transportation rights. Mr. Stanley testified that through the RFP process, Petitioner has awarded a variety of deal structures to multiple suppliers at a variety of locations to create the most competitive, low-cost, and diversified portfolio reasonably possible.

Mr. Stanley testified that Petitioner purchased gas supplies from thirty-four (34) different suppliers during the winter period of November 2008 through March of 2009. Petitioner also has short-haul firm transportation agreements with both Panhandle (MDQ of 20,000 Dth) and Trunkline (MDQ of 20,000 Dth). The purpose of these contracts is to move gas between Petitioner's Zone "A" and "B" service areas within its gas service territory. Additionally, Petitioner has short-haul firm transportation contracts with Vector (MDQ of 43,000 Dth); and Northern Border (MDQ of 165,000 Dth).

Mr. Stanley testified that since the filing of testimony in Cause No. 41338 GCA 10, negotiations were completed to replace transportation and storage services with Natural Gas Pipeline, Panhandle Energy, Trunkline Gas and Texas Eastern Gas Pipeline. These contracts had been set to expire on March 31, 2009. He indicated that no contracts are due to expire during the GCA11 period, i.e., during the twelve month period beginning November 1, 2009, and ending October 31, 2010.

Mr. Stanley described the hedging program that is part of Petitioner's long-term gas supply procurement policy. According to Mr. Stanley, given the current price volatility inherent in the marketplace and the expectation that these conditions may continue, Petitioner has continued its forward price volatility mitigation program for the upcoming winter. Petitioner has established a plan that targets hedging the price on 20% of projected flowing pipeline gas supply purchase requirements for the winter months of November through March. Petitioner has elected to achieve its hedge objective through the use of a dollar-cost-averaging methodology with the pre-planned purchase of NYMEX Futures contracts at pre-planned execution times, spread evenly across the preceding twelve (12) month period. This strategy was selected to satisfy the primary objective of insulating customers from continued price volatility while maintaining a simplified and transparent program with minimal transaction costs.

According to Mr. Stanley, the Company's price volatility mitigation program for the five-month winter period beginning November 1, 2009 is consistent with the Stipulation and Settlement Agreement as filed on June 11, 2004 ("Agreement") and approved by the Commission's August 18, 2004 Order in Cause No. 41338-GCA5. He further testified that in response to the Commission's recommendations, Petitioner has introduced an element of discretion in the manner in which Petitioner fixes the price of 20% of its projected peak gas supply purchase requirements. Previously, Petitioner followed an established schedule which resulted in the purchase of specific volumes on specific dates. Now, in response to the Commission's recommendations, Petitioner may use its discretion to purchase more or less on a given date than was originally scheduled. However, the total volumes purchased would still need to be consistent with Petitioner's volatility mitigation plan objective of fixing approximately 20% of its projected peak gas supply purchase requirements.

Ms. Cherven, Manager of Compliance in the Rates Department for Petitioner, submitted testimony detailing the various schedules required by the Commission's GCA regulations, reconciliation calculations and the resulting GCA factors that became effective November 1, 2009. Ms. Cherven confirmed that Petitioner has properly applied its gas cost adjustments since its last-filed GCA.

4. **<u>OUCC's Testimony</u>**. Mr. Jerome D. Mierzwa, a Principal and Vice President of

Exeter Associates, Inc. ("Exeter") provided testimony on behalf of the OUCC. Mr. Mierzwa explained that Exeter specializes in providing public-utility-related consulting services, and was retained by the OUCC to review the reasonableness of the reported gas costs of Petitioner for the GCA 11 audit period, which covers the period from August 1, 2008 through July 31, 2009. He also evaluated the Demand Cost Reduction Incentive Program ("DCR"), Capacity Release Revenue Sharing Mechanism and Gas Cost Incentive Mechanism ("GCIM") under which Petitioner operates.

Mr. Mierzwa's testimony set forth the results of his review and recommendations. He recommended only one adjustment, relating to pipeline demand charges and capacity release revenues, as set forth more fully below.

Mr. Mierzwa testified that in general, Petitioner has reasonably administered its DCR and Capacity Release Revenue Sharing Mechanism during the GCA 11 period. Mr. Mierzwa stated that in the settlement approved by the Commission in Cause No. 42884, Petitioner was assigned cost responsibility for a portion of the interstate pipeline demand charges associated with capacity retained by Petitioner to be the Supplier of Last Resort ("SOLR") for Choice customers. On a monthly basis, the actual demand charges incurred by Petitioner during the corresponding month of a "base period" are multiplied by (1) the ratio of total Choice throughput divided by total GCA and Choice throughput, and; (2) Petitioner's responsibility percentage. Mr. Mierzwa testified Petitioner reasonably administered its DCR and that there was no evidence that Petitioner improperly attempted to benefit under the DCR during the GCA 11 period.

With regard to capacity release revenues, Mr. Mierzwa stated the settlement in Cause No. 42884 allowed Petitioner to retain 15% of the capacity release revenues it is able to generate as an incentive. He testified that Petitioner realized $13,225,500 in capacity release revenues during the GCA 11 audit review period, of which it was entitled to retain $2,230,000. According to Mr. Mierzwa, Exeter's audit revealed that generally, Petitioner reasonably administered its capacity release revenue sharing mechanism during the GCA 11 period. Exeter found no evidence that Petitioner improperly attempted to benefit under the mechanism.

Mr. Mierzwa did recommend one adjustment. He testified that Petitioner's pipeline demand charges and capacity release revenues were improperly accounted for during August and October 2008, and that a reduction of $86,366 to GCA 11 costs was appropriate. He stated that the issue was addressed during an on-site audit of Petitioner and that Petitioner indicated it conceptually agreed with his recommended adjustment, but would need to further investigate the amount of the adjustment.

Mr. Mierzwa also reviewed Petitioner's GCIM. Petitioner's GCIM is an incentive mechanism designed to reward the Company if it acquires gas at less than market prices and penalize Petitioner if it acquires gas at more than market prices. The GCIM procedures were approved as part of the Stipulation and Agreement in Cause No. 41338-GCA5. Under the GCIM, the actual cost of each gas purchase made by Petitioner is compared to a benchmark which reflects the cost of the purchase had it been made at a market price for the location, type of purchase and time at which the purchase was made. Index prices reported in gas industry publications serve as market prices under the GCIM. On a monthly basis, Petitioner's actual gas costs are compared to the benchmark. If Petitioner's actual gas costs are less than the benchmark, Petitioner is rewarded with 50 percent of the difference between actual costs and benchmark. If Petitioner's actual gas costs exceed the benchmark, Petitioner is penalized 50 percent of the difference between actual costs and the benchmark.

Mr. Mierzwa testified that Petitioner has administered the GCIM consistent with the procedures approved in Cause No. 41338-GCA5. He further testified that Petitioner has reasonably administered the agreed upon exchange transaction tagging procedures. Since tagging procedures have been implemented, Mr. Mierzwa testified they have revealed that to date, Petitioner's exchange activities have not had an adverse impact on GCA costs. He recommended the tagging procedures should be continued at this time.

Finally, Mr. Mierzwa testified that Petitioner was able to adequately support its reported actual gas cost and incentive mechanism performance for the review period. As part of the review, Mr. Mierzwa stated Exeter sought supporting documentation for the Petitioner's reported actual gas costs and GCIM and DCR performance, which supported Petitioner's claims.

5. **<u>Petitioner's Rebuttal Testimony</u>**. Ms. Katherine Cherven provided rebuttal testimony on behalf of Petitioner, and addressed two issues: (1) Mr. Mierzwa's proposed adjustment relating to improper accounting for pipeline demand charges and capacity release revenues; and (2) an additional $1.67 million refund that will be provided to Petitioner's GCA customers that relates to the methodology employed when calculating unaccounted for gas ("UAFG").

Ms. Cherven testified that Petitioner agreed with Mr. Mierzwa that an adjustment was appropriate. She testified that Petitioner determined that invoices were erroneously deleted in the gas management system in August 2008 and October 2008. The erroneously-deleted invoices for the production months of July and September 2008 involve identical amounts and were related to the same transportation contract. This created adjustment records, as these deleted invoices were related to previously accrued estimates for July 2008 and September 2008. These adjustment records reduced the pipeline demand dollars that the Schedule 8B Pipeline Demand Cost Reduction Program sharing calculation is based on for each of those months. The reduced demand dollars resulted in higher savings dollars, thus resulting in a higher sharing dollar amount that was charged back on Schedule 8 in August 2008 and October 2008. Ms. Cherven testified that the amount of the adjustment should be a net credit to GCA customers of $126,000. She further stated that the OUCC indicated it has no disagreement with the adjustment proposed by Petitioner.

Ms. Cherven also testified about a $1.67 million refund that will be provided to Petitioner's GCA customers. According to Ms. Cherven, one of the issues in Cause No. 41338-GCA 10 related to the methodology to be employed when determining Petitioner's level of unaccounted for gas. Petitioner proposed the use of a four-year average, and the OUCC proposed that the most recent year's UAFG should be employed. In the final order issued on October 21, 2009, the Commission determined that Petitioner should use the most recent year's UAFG when determining the level of UAFG. At the time the GCA10 order was issued, Petitioner had already filed its schedules and case-in-chief for GCA 11. In preparing those exhibits, Petitioner used the four-year average UAFG of 0.62%, instead of the most recent year's experience of 1.04%. Restating the figures set forth in Schedule 11 to reflect the change in UAFG methodology results in a refund to GCA customers of $1,665,921. Ms. Cherven testified that the OUCC indicated it has no disagreement with the refund proposed by Petitioner.

6. **Commission Findings**. The only issue raised by the OUCC relates to an adjustment that is needed to correct an apparently erroneous deletion of invoices for the months of August 2008 and October 2008. Petitioner's witness Ms. Cherven testified that GCA customers should be credited $126,000, and the OUCC did not disagree with the proposed adjustment. After due consideration, the Commission finds that Petitioner's proposed adjustment should be approved.

The Commission further finds that Petitioner's proposed refund of $1,665,921 should be approved and refunded to Petitioner's GCA customers in its next quarterly filing. Finally, based on the evidence presented, the Commission finds that Petitioner's proposed GCA factors should be approved as just and reasonable and consistent with the statutory standards set forth in I.C. § 8-1-2-42(g) and the Commission's order in Cause No. 41338.

7. **Reconciliation**. I.C. § 8-1-2-42(g)(3)(D) requires the Commission to find that Petitioner reconciled its estimation for a previous recovery period with the actual purchased gas costs for that period. Witness Cherven testified that Petitioner had net over-collected revenues for the period August 1, 2008 through July 31, 2009 of $196,237,497. Witness Cherven testified that Petitioner's net over-collection was due primarily to the actual commodity cost of gas being lower than estimates.

8. **Resulting Gas Cost Adjustment Factors**. Combining the total pipeline demand cost of gas to be recovered of $43,385,235 with the contracted storage and transmission costs of $37,407,200 and $108,820 results in total estimated annual demand costs of $80,901,255 for the twelve-month recovery period beginning with the November, 2009 billing cycle. After dividing by estimated annual sales, the requested annualized demand costs per therm are calculated for the November 1, 2009 - October 2010 period as follows:

Class 1 Residential	$.0988/Therm
Class 2 General Service and Class 4 CNG	$.0793/Therm
Class 3 Interruptible	$.0000/Therm

With regard to the additional costs associated with Storage and Transmission, NIPSCO offered evidence supporting the following charges:

FDTS	a charge of	$0.0177/Therm

All prior variances for these surcharges are included in Petitioner's monthly commodity filings.

9. **Interim Rates**. The Commission is unable to determine whether Petitioner will earn an excess return while this GCA is in effect. Accordingly, the Commission finds that the approved rates herein should be interim rates subject to refund, pending reconciliation of the gas costs in a subsequent GCA, and in the event an excess return is earned.

10. **Removal of Refund Obligation**. The Commission determined in its order in Cause No. 41338-GCA10 that the rates approved therein should be interim rates subject to refund, pending reconciliation of the gas costs in a subsequent GCA, and in the event an excess return is earned. Ms. Cherven stated that Petitioner is requesting the refund obligation be eliminated for the months of August through December, 2008 and January through July, 2009. She noted that a similar procedure had historically been established in the quarterly GCA filings. The testimony of Ms. Cherven reconciles Petitioner's estimated gas costs to its actual gas costs. Also, as a result of its quarterly NGA filings, the Commission finds that Petitioner has not earned an excess return during the twelve month period commencing August 1, 2007. Accordingly the Commission shall grant Petitioner's request that the refund obligation for this period be removed.

11. **Confidential Filing**. On November 3, 2009, the Presiding Officers made a preliminary finding that certain designated information marked "Confidential and Protected Material" as requested in Petitioner's *Unopposed Motion for the Establishment of Confidential Procedures* should be treated as confidential in accordance with I.C. § 5-14-3-4 and that confidential procedures should be followed with respect to this Confidential Information. Upon review of the Confidential Information submitted pursuant to the Presiding Officers' preliminary determination, the Commission confirms its prior finding and concludes that the information for which Petitioner sought confidential treatment contains confidential, proprietary, competitively sensitive trade secret information that has economic value to Petitioner from neither being known to, nor ascertainable by, its competitors and other persons who could obtain economic value from the knowledge and the use of such information; that the public disclosure of such information would have a substantial detrimental effect on Petitioner; and that the information is subject to efforts of Petitioner that are reasonable under the circumstances to maintain its secrecy. Accordingly, the Confidential Information submitted to the Commission as Exhibit 2G is exempt from the public access requirements of I.C. §§ 5-14-3-3, 8-1-2-29, and 24-2-3-1 and shall continue to be held as confidential by the Commission.

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

1. The Petition of NIPSCO for a Gas Cost Adjustment for natural gas service as set out above, and the same is hereby approved subject to refund, until the gas costs are reconciled in a subsequent GCA, and in the event that an excess rate of return is earned.

2. Petitioner shall reduce gas costs for its GCA customers by $1,665,921 in its next

GCA filing, in accordance with Finding Paragraph No. 6 above.

3. Petitioner shall file with the Natural Gas Division of the Commission the tariff changes approved herein.

4. The refund obligation imposed by the October 21, 2009 Order in Cause No. 41338-GCA10 for the twelve month period commencing August 1, 2008 is hereby removed.

5. Petitioner's request for confidential trade secret treatment is hereby granted, and such Confidential Information shall be excepted from public disclosure.

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

HARDY, ATTERHOLT, LANDIS, MAYS AND ZIEGNER CONCUR:

APPROVED: MAR 24 2010

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

Brenda Howe

Brenda Howe
Secretary to the Commission