FILED
February 02, 2012
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF A FUEL COST ADJUSTMENT TO BE APPLICABLE DURING THE BILLING MONTHS OF MAY, JUNE AND JULY 2012, PURSUANT TO IND. CODE § 8-1-2-42 AND CAUSE NO. 43969 AND FOR APPROVAL OF RATEMAKING TREATMENT FOR THE COST OF WIND POWER PURCHASES PURSUANT TO CAUSE NO. 43393.	)	CAUSE NO. 38706-FAC94

SUBMISSION OF DIRECT TESTIMONY AND EXHIBITS

Northern Indiana Public Service Company ("NIPSCO" or "Petitioner"), by counsel, hereby submits its Direct Testimony and Exhibits.

Respectfully submitted,

Erin Casper Borissov

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by email transmission upon the following:

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Dated this 2nd day of February, 2012.

Erin Casper Borissov

Erin Casper Borissov

VERIFIED DIRECT TESTIMONY OF KATHERINE A. CHERVEN

Q1. Please state your name, business address and title.

A1. My name is Katherine A. Cherven. My business address is 801 East 86th Avenue, Merrillville, Indiana. I am the Manager of Compliance in the Rates and Regulatory Finance Department of Northern Indiana Public Service Company ("NIPSCO" or the "Company").

Q2. Please describe your educational and employment background.

A2. I received a Bachelor of Science degree in Accounting/Management from Calumet College of St. Joseph. I have been employed by NIPSCO or NiSource in various departments for a period of over twenty years. I began my employment with NIPSCO in 1981 in the Auditing Department. Since joining the Company, I have held various accountant and supervisory positions in the General Accounting, Property Records, and Payroll Departments. I left the Company in 1996, but was recalled as a consultant to provide services during the 1999-2003 timeframe. In May 2006, I accepted full-time employment with NIPSCO as the Manager of Compliance in the Rates and Regulatory Finance Department.

Q3. What are your responsibilities as Manager of Compliance?

A3. As Manager of Compliance, I am responsible for the preparation and coordination of NIPSCO's Fuel Adjustment Clause ("FAC"), Gas Cost Adjustment, Resource Adequacy Adjustment and Regional Transmission Organization Adjustment filings with regulatory agencies.

Q4. What is the purpose of your testimony?

A4. The purpose of my testimony is to explain changes in the schedules supporting the proposed FAC factors in this proceeding necessitated by the Commission's December 21, 2011 Order in Cause No. 43969 approving a Stipulation and Settlement Agreement by and among NIPSCO, the Indiana Office of Utility Consumer Counselor, NLMK Indiana f/k/a Beta Steel Corporation, Indiana Municipal Utilities Group, and NIPSCO Industrial Group (the "Rate Order"). I also explain the schedules supporting the proposed FAC factors in this proceeding.

Q5. What exhibits are you sponsoring?

A5. I am sponsoring Petitioner's Exhibit Nos. 1-A through 1-D, all of which were prepared by me or under my direction and supervision.

Q6. Please explain Petitioner's Exhibit No. 1-A.

A6. Petitioner's Exhibit No. 1-A is the Verified Petition filed in this Cause, including Petitioner's Exhibits A and B attached thereto.

Q7. What does Petitioner's Exhibit No. 1-A request?

A7. In its Verified Petition, NIPSCO requests approval of a fuel cost adjustment of (a) $(0.000702) per kilowatt hour for customers billed under Rate Schedules 611, 612, 613, 620, 621, 622, 623, 624, 625, 626, 632, 633, 634, 641, 642, 644, 650, 655 and 660, Rate Code 647 and Rider 676 and (b) $0.005567 per kilowatt hour for two existing customers billed under Rate Code 647 under contracts approved by the Commission that contain a different base fuel cost and require a special calculation until their expiration, to be applicable during the billing months of May, June and July 2012.

Q8. Please explain Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5 and Petitioner's Exhibit No. 1-B.

A8. Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5 shows actual and forecasted sales and fuel costs in the period October, November and December 2011. Petitioner's Exhibit No. 1-B shows NIPSCO's actual fuel costs for the period January 2007 through December 2011, the last month for which fuel costs were available at the time of preparation of the Verified Petition.

Q9. Please explain Petitioner's Exhibit No. 1-C and Petitioner's Exhibit No. 1-D.

A9. Petitioner's Exhibit No. 1-C is an analysis of the change in the Fuel Cost Factors requested in this FAC filing, from the factors approved in NIPSCO's last FAC filing. The change is shown broken down into the following elements that make up the difference in factors: (1) Fuel Cost Excluding Variance, (2) Total Variance Adjustment, (3) Interruptible Credit Recovery and (4) Tax Included in Calculation. Petitioner's Exhibit No. 1-D shows the estimated cost, MWh and unit cost in mills per kilowatt hour for the current filing along with those from the prior filing.

Q10. Were these exhibits prepared by you or under your direction and supervision and are the representations made therein true and correct, to the best of your knowledge, information and belief?

A10. Yes.

Q11. Please explain how the Rate Order impacts NIPSCO's FAC filings.

A11. The Rate Order impacts NIPSCO's FAC filings as follows:

<u>Changes under new 600 rates</u>

- The base fuel cost reduction changes to 28.729 mills per kwh.
- Inclusion of recovery of 25% of the actual interruptible credits paid on Rider 675 for the applicable period (same months as FAC reconciliation months).

<u>Schedule 1, page 1 of 2</u>

- There is a new Line 28 to include the factor for the recovery of 25% of the interruptible credits. Credits were paid pursuant to Rider 675 for December 27 – 31, 2011.
- The base cost reduction is updated from 22.556 to 28.729 on Line 29.

<u>Schedule 1, page 2 of 2</u>

- NIPSCO has two existing special contracts, which by their terms expire six months following implementation of new rates, which will be billed under Rate Code 647. The special contracts contain a different base fuel cost and will require a special calculation until their expiration. After that period, which will be no longer than 6 months, it is anticipated that these services will move to Rate 632.
- This Schedule will take the adjusted fuel cost factor on Schedule 1, page 1 Line 29 and reduce it for the 22.556 base cost of gas to create the FAC factor for Rate code 647 on Appendix B.

<u>Revised Exhibit 1-C</u>

- Additional lines relating to the Interruptible Credit Recovery have been added.

<u>Customer Credit Adjustment (formerly Appendix C)</u>

- The revenue credit and the sharing mechanism approved in Cause No. 41746 is no longer in effect. NIPSCO anticipates that by the end of January 2012, reconciliations of the revenue credit will be performed for all billed months. Therefore, the final balance of any over or under credit will be included in the variance in the FAC-95 filing.

Q12. How has NIPSCO treated the recovery of its purchased power for the months of October, November and December 2011?

A12. As explained by NIPSCO Witness Dan Williamson, in accordance with the purchased power benchmark established in Cause No. 43526, NIPSCO has included its recoverable jurisdictional purchased power costs for the months of October, November and December 2011.

Q13. Will NIPSCO provide the Indiana Office of Utility Consumer Counselor ("OUCC") with all purchase power records with respect to power purchased during the reconciliation period in this FAC filing?

A13. Yes. NIPSCO will mail those records to the OUCC, and its auditor, as part of the audit materials the same day this testimony is filed with the Commission.

Q14. Has NIPSCO included any charges or credits resulting from the operations of the Midwest Independent Transmission System Operator, Inc.'s ("MISO") markets for recovery in this FAC filing?

A14. Yes. NIPSCO has included actual fuel-related charges and credits resulting from MISO market operations for the months of October, November and December 2011, as summarized on Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 7. Mr. Williamson describes these costs as well as the MISO settlement process and explains that NIPSCO has considered the operational changes stemming from the MISO markets and included an estimate of fuel-related MISO costs as part of the forecast in this FAC filing.

Q15. Have you reviewed the Commission's Order in Cause No. 42685 issued June 1, 2005?

A15. Yes.

Q16. Is NIPSCO's proposed recovery of charges and credits resulting from MISO markets consistent with your understanding of the Commission's Order in Cause No. 42685?

A16. Yes.

Q17. Have you reviewed the Commission's Order in Cause No. 43665 issued June 30, 2009?

A17. Yes.

Q18. Is NIPSCO's proposed recovery of Day-Ahead and Real-Time RSG

distribution amounts consistent with your understanding of the Commission's Order in Cause No. 43665?

A18. Yes.

Q19. Is NIPSCO proposing to recover any Contestable Real-Time RSG distribution amounts in this FAC filing as that term is defined by the Settlement Agreement approved by the Commission's Order in Cause No. 43665?

A19. No.

Q20. Have you reviewed the Commission's Phase II Order in Cause No. 43426 issued June 30, 2009?

A20. Yes.

Q21. Is NIPSCO's proposed recovery of Ancillary Services Market charge types consistent with your understanding of the Commission's Phase II Order in Cause No. 43426?

A21. Yes.

Q22. Has NIPSCO provided any back-up and maintenance power service during October, November and December 2011?

A22. Yes.

Q23. What is the current gas transmission net capacity cost included for recovery in this filing?

A23. Pursuant to the Commission's October 28, 2009 Order in Cause No. 38706-FAC84 NIPSCO has included $412,600 of net capacity cost for October, November and December 2011.

Q24. Does this conclude your prepared direct testimony?

A24. Yes.

VERIFICATION

I, Katherine A. Cherven, Manager of Compliance in the Rates and Regulatory Finance Department of the Northern Indiana Public Service Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Katherine A. Cherven

Katherine A. Cherven

Dated: February 2, 2012

NORTHERN INDIANA PUBLIC SERVICE COMPANY

ACTUAL COST OF FUEL TO GENERATE ELECTRICITY AND
THE ACTUAL COST OF FUEL INCLUDED IN THE COST OF PURCHASED ELECTRICITY
FOR THE PERIOD OF JANUARY 2007 TO JUNE 2007 INCLUSIVE

2007

LINE NO.	DESCRIPTION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	LINE NO.
	KWH SOURCE (000'S)							
1	Steam Generation	1,140,723	1,104,933	1,149,429	1,142,580	1,213,679	1,275,907	1
2	Nuclear Generation	-	-	-	-	-	-	2
3	Hydro Generation	5,816	5,096	5,599	7,455	5,772	3,149	3
4	Other Generation	421	500	1,266	352	308	296	4
5	Purchases through MISO	203,989	253,505	175,143	158,205	177,679	111,175	5
6	Purchased Power other than MISO	166,627	127,216	122,665	70,183	106,745	282,843	6
7	Power Received for Other Systems	149,005	157,368	144,968	124,428	125,451	143,757	7
	LESS:							
8	Jurisdictional Sales not Subject to FAC	134,122	117,625	118,282	121,023	115,793	121,054	8
9	Intersystem Sales through MISO	36,720	46,975	46,455	33,562	52,566	116,314	9
10	Intersystem Sales other than MISO	1,628	3,547	1,936	1,736	1,904	1,738	10
11	Power Transmitted for Other Systems	149,005	157,368	144,968	124,428	125,451	143,757	11
12	Energy Losses and Company Use	57,762	80,054	5,611	68,240	112,292	117,219	12
13	SALES (S)	1,287,344	1,243,049	1,281,819	1,154,214	1,221,628	1,317,045	13
	FUEL COST (F)							
14	Steam Generation	$ 22,390,665	$ 21,652,443	$ 22,573,891	$ 22,325,627	$ 25,296,562	$ 26,014,367	14
15	Nuclear Generation	-	-	-	-	-	-	15
16	Hydro Generation	-	-	-	-	-	-	16
17	Other Generation	47,018	90,409	141,365	54,836	41,220	44,575	17
18	Purchases through MISO	7,679,291	16,208,788	8,545,046	8,419,432	10,451,127	4,955,430	18
19	MISO Components of Cost of Fuel	1,644,115	2,799,790	1,318,409	1,525,760	447,489	1,258,960	19
20	Purchased Power other than MISO	7,322,853	5,732,075	7,620,230	3,762,923	6,286,423	16,683,065	20
	LESS:							
21	Jurisdictional Sales not Subject to FAC	3,553,831	3,914,325	3,115,075	3,176,583	3,581,941	3,941,881	21
22	Intersystem Sales through MISO	463,382	658,660	613,843	481,465	799,613	1,708,376	22
23	Intersystem Sales other than MISO	779,812	365,869	2,490,165	2,363,907	199,414	119,581	23
24	Transmission Losses	176,163	178,466	221,873	105,537	152,012	299,623	24
25	TOTAL FUEL COSTS (F)	$ 34,110,754	$ 41,366,185	$ 33,757,985	$ 29,961,086	$ 37,789,841	$ 42,886,936	25
26	FUEL COST PER KWH (IN MILLS) F/S	26.497	33.278	26.336	25.958	30.934	32.563	26
27	FUEL COST PER KWH (IN DOLLARS) F/S	0.026497	0.033278	0.026336	0.025958	0.030934	0.032563	27

NORTHERN INDIANA PUBLIC SERVICE COMPANY

ACTUAL COST OF FUEL TO GENERATE ELECTRICITY AND
THE ACTUAL COST OF FUEL INCLUDED IN THE COST OF PURCHASED ELECTRICITY
FOR THE PERIOD OF JULY 2007 TO DECEMBER 2007 INCLUSIVE

LINE NO.	DESCRIPTION	2007 JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	LINE NO.
	KWH SOURCE (000'S)							
1	Steam Generation	1,269,778	1,465,300	1,240,369	1,319,032	1,230,535	1,222,950	1
2	Nuclear Generation	-	-	-	-	-	-	2
3	Hydro Generation	1,362	2,325	3,867	2,055	2,185	7,131	3
4	Other Generation	11,291	6,856	2,658	1,516	1,282	2,227	4
5	Purchases through MISO	146,513	72,441	105,472	90,453	85,540	78,810	5
6	Purchased Power other than MISO	350,395	413,975	245,774	146,512	144,962	239,944	6
7	Power Received for Other Systems	186,098	210,166	204,905	120,408	136,341	140,693	7
	LESS:							
8	Jurisdictional Sales not Subject to FAC	126,782	129,626	121,403	138,798	126,096	128,410	8
9	Intersystem Sales through MISO	156,867	206,308	64,552	43,267	45,831	31,856	9
10	Intersystem Sales other than MISO	2,413	1,773	5,192	2,331	1,861	1,786	10
11	Power Transmitted for Other Systems	186,098	210,166	204,905	120,408	136,341	140,693	11
12	Energy Losses and Company Use	95,552	106,550	38,581	28,662	105,831	136,353	12
13	SALES (S)	1,397,726	1,516,640	1,368,412	1,346,510	1,184,885	1,252,657	13
	FUEL COST (F)							
14	Steam Generation	$ 27,504,211	$ 30,036,110	$ 25,172,856	$ 27,405,722	$ 25,752,780	$ 25,861,149	14
15	Nuclear Generation	-	-	-	-	-	-	15
16	Hydro Generation	-	-	-	-	-	-	16
17	Other Generation	1,779,689	(26,422)	275,216	179,795	124,369	249,531	17
18	Purchases through MISO	6,067,992	3,573,797	4,424,025	4,716,175	3,175,286	2,768,040	18
19	MISO Components of Cost of Fuel	76,828	803,756	(886,187)	46,680	(639,351)	9,523,365	19
20	Purchased Power other than MISO	21,318,822	28,319,364	11,046,643	6,415,070	5,892,583	11,020,262	20
	LESS:							
21	Jurisdictional Sales not Subject to FAC	4,490,999	4,594,334	3,157,328	3,506,486	3,124,785	4,498,248	21
22	Intersystem Sales through MISO	2,653,695	3,308,655	937,578	565,592	649,654	527,046	22
23	Intersystem Sales other than MISO	(246,249)	567,578	128,070	(1,807)	(22,399)	127,470	23
24	Transmission Losses	337,449	481,766	221,285	210,514	204,976	154,109	24
25	Purchases over the Benchmark	-	-	-	1,751,693	986,065	429,096	25
26	TOTAL FUEL COSTS (F)	$ 49,511,648	$ 53,754,272	$ 35,588,292	$ 32,730,964	$ 29,362,586	$ 43,686,378	26
27	FUEL COST PER KWH (IN MILLS) F/S	**35.423**	**35.443**	**26.007**	**24.308**	**24.781**	**34.875**	27
28	FUEL COST PER KWH (IN DOLLARS) F/S	0.035423	0.035443	0.026007	0.024308	0.024781	0.034875	28

NORTHERN INDIANA PUBLIC SERVICE COMPANY

ACTUAL COST OF FUEL TO GENERATE ELECTRICITY AND
THE ACTUAL COST OF FUEL INCLUDED IN THE COST OF PURCHASED ELECTRICITY
FOR THE PERIOD OF JANUARY 2008 TO JUNE 2008 INCLUSIVE

2008

LINE NO.	DESCRIPTION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	LINE NO.
	KWH SOURCE (000'S)							
1	Steam Generation	1,152,717	1,136,052	1,183,607	1,116,831	1,210,921	1,358,661	1
2	Nuclear Generation	-	-	-	-	-	-	2
3	Hydro Generation	3,778	5,926	6,201	5,512	5,069	6,229	3
4	Other Generation	193	237	240	165	94	8,171	4
5	Purchases through MISO	139,285	24,719	60,282	36,073	18,460	166,647	5
6	Purchased Power other than MISO	333,215	360,358	273,118	285,568	220,544	46,291	6
7	Power Received for Other Systems	187,057	175,773	156,869	150,904	147,603	147,388	7
	LESS:							
8	Jurisdictional Sales not Subject to FAC	152,114	118,993	127,829	117,526	112,218	112,236	8
9	Intersystem Sales through MISO	39,808	65,492	32,499	55,113	61,635	63,159	9
10	Intersystem Sales other than MISO	2,354	2,191	2,290	1,683	1,836	1,877	10
11	Power Transmitted for Other Systems	187,057	175,773	156,869	150,904	147,603	147,388	11
12	Energy Losses and Company Use	2,381	86,915	63,246	5,518	86,406	144,079	12
13	SALES (S)	1,432,531	1,253,701	1,297,584	1,264,309	1,192,993	1,264,648	13
	FUEL COST (F)							
14	Steam Generation	$23,345,583	$25,095,473	$26,154,913	$ 24,975,234	$ 27,487,665	$ 31,092,287	14
15	Nuclear Generation	-	-	-	-	-	-	15
16	Hydro Generation	-	-	-	-	-	-	16
17	Other Generation	41,769	31,997	33,139	27,121	26,067	1,568,791	17
18	Purchases through MISO	5,650,195	50,554	2,738,178	2,076,368	1,564,381	13,428,568	18
19	MISO Components of Cost of Fuel	1,076,437	2,138,115	2,689,067	(2,736,530)	(1,816,889)	2,838,471	19
20	Purchased Power other than MISO	18,043,194	20,252,595	17,223,177	17,404,214	11,270,710	2,176,133	20
	LESS:							
21	Jurisdictional Sales not Subject to FAC	4,467,255	3,898,509	4,314,353	3,448,796	3,249,983	3,861,508	21
22	Intersystem Sales through MISO	584,868	1,061,887	462,126	828,104	947,684	1,178,687	22
23	Intersystem Sales other than MISO	86,243	689,266	59,537	860,596	(99,419)	534,712	23
24	Transmission Losses	129,105	218,960	165,367	192,166	219,840	341,527	24
25	Purchases over the Benchmark	2,339,052	833,188	665,208	208,172	-	2,423,744	25
26	TOTAL FUEL COSTS (F)	$40,550,655	$40,866,924	$43,171,883	$ 36,208,573	$ 34,213,846	$ 42,764,072	26
27	FUEL COST PER KWH (IN MILLS) F/S	**28.307**	**32.597**	**33.271**	**28.639**	**28.679**	**33.815**	27
28	FUEL COST PER KWH (IN DOLLARS) F/S	0.028307	0.032597	0.033271	0.028639	0.028679	0.033815	28

NORTHERN INDIANA PUBLIC SERVICE COMPANY

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LINE NO.	DESCRIPTION	2008 JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	LINE NO.
	KWH SOURCE (000'S)							
1	Steam Generation	1,510,862	1,432,246	1,068,181	982,807	1,191,339	1,436,440	1
2	Nuclear Generation	-	-	-	-	-	-	2
3	Hydro Generation	4,297	2,926	2,900	1,644	1,797	4,257	3
4	Other Generation	2,595	2,922	251	1,442	522	8,879	4
5	Purchases through MISO	150,887	166,940	331,935	343,412	69,935	35,894	5
6	Purchased Power other than MISO	35,759	64,903	74,390	31,902	33,908	38,108	6
7	Power Received for Other Systems	123,112	242,930	169,874	120,815	148,201	161,412	7
	LESS:							
8	Jurisdictional Sales not Subject to FAC	111,746	113,799	114,715	116,419	108,345	114,599	8
9	Intersystem Sales through MISO	33,605	34,550	4,230	6,387	51,433	124,142	9
10	Intersystem Sales other than MISO	2,190	2,654	1,912	2,163	2,043	2,150	10
11	Power Transmitted for Other Systems	123,112	242,930	169,874	120,815	148,201	161,412	11
12	Energy Losses and Company Use	157,085	75,379	(15,302)	67,016	90,990	68,423	12
13	SALES (S)	1,399,774	1,443,555	1,372,102	1,169,222	1,044,690	1,214,264	13
	FUEL COST (F)							
14	Steam Generation	$33,645,180	$32,541,269	$23,919,000	$ 19,874,067	$ 25,520,377	$ 32,184,626	14
15	Nuclear Generation	-	-	-	-	-	-	15
16	Hydro Generation	-	-	-	-	-	-	16
17	Other Generation	475,030	385,197	38,293	166,250	72,648	826,009	17
18	Purchases through MISO	12,524,858	10,595,172	14,317,822	12,217,816	2,185,936	1,532,823	18
19	MISO Components of Cost of Fuel	3,586,890	981,934	1,468,187	2,461,019	174,325	1,887,619	19
20	Purchased Power other than MISO	1,258,888	3,121,415	3,460,808	423,132	209,523	349,171	20
	LESS:							
21	Jurisdictional Sales not Subject to FAC	3,651,798	3,271,835	3,342,541	3,143,080	2,520,213	2,917,347	21
22	Intersystem Sales through MISO	444,826	488,794	50,593	100,347	796,631	2,195,297	22
23	Intersystem Sales other than MISO	54,030	68,785	287,549	138,760	61,401	302,728	23
24	Transmission Losses	231,695	250,892	28,779	55,695	283,539	452,104	24
25	Purchases over the Benchmark	1,600,476	2,041,031	675,195	137,747	200,490	1,279	25
26	TOTAL FUEL COSTS (F)	$45,508,021	$41,503,650	$38,819,453	$ 31,566,655	$ 24,300,535	$ 30,911,493	26
27	FUEL COST PER KWH (IN MILLS) F/S	**32.511**	**28.751**	**28.292**	**26.998**	**23.261**	**25.457**	27
28	FUEL COST PER KWH (IN DOLLARS) F/S	0.032511	0.028751	0.028292	0.026998	0.023261	0.025457	28

NORTHERN INDIANA PUBLIC SERVICE COMPANY

ACTUAL COST OF FUEL TO GENERATE ELECTRICITY AND
THE ACTUAL COST OF FUEL INCLUDED IN THE COST OF PURCHASED ELECTRICITY
FOR THE PERIOD OF JANUARY 2009 TO JUNE 2009 INCLUSIVE

2009

LINE NO.	DESCRIPTION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	LINE NO.
	KWH SOURCE (000'S)							
1	Steam Generation	1,086,493	923,910	1,039,133	840,047	1,119,220	1,287,291	1
2	Nuclear Generation	-	-	-	-	-	-	2
3	Hydro Generation	4,741	5,913	7,092	7,590	7,130	6,705	3
4	Other Generation	411	65	111	216	224	270	4
5	Purchases through MISO	345,094	295,900	207,312	289,720	83,404	45,452	5
6	Purchased Power other than MISO	38,662	36,224	36,390	47,724	59,397	51,273	6
7	Power Received for Other Systems	192,793	193,555	115,318	146,391	123,051	133,499	7
	LESS:							
8	Jurisdictional Sales not Subject to FAC	129,168	118,277	117,067	125,567	153,360	121,404	8
9	Intersystem Sales through MISO	32,104	3,148	22,177	2,206	44,149	72,313	9
10	Intersystem Sales other than MISO	90	38	14	-	5	2	10
11	Power Transmitted for Other Systems	192,793	193,555	115,318	146,391	123,051	133,499	11
12	Energy Losses and Company Use	36,647	12,982	49,829	51,511	94,589	158,524	12
13	SALES (S)	1,277,392	1,127,567	1,100,951	1,006,013	977,272	1,038,748	13
	FUEL COST (F)							
14	Steam Generation	$28,163,856	$ 25,991,029	$ 27,832,511	$ 22,385,072	$ 29,450,746	$ 33,531,781	14
15	Nuclear Generation	-	-	-	-	-	-	15
16	Hydro Generation	-	-	-	-	-	-	16
17	Other Generation	62,615	18,648	28,107	22,723	25,523	30,764	17
18	Purchases through MISO	12,743,485	8,595,521	4,332,309	7,425,689	1,907,364	890,377	18
19	MISO Components of Cost of Fuel	2,740,248	2,862,637	1,669,269	2,882,989	(538,557)	362,511	19
20	Purchased Power other than MISO	1,968	(22,305)	(4,166)	666,616	2,104,549	773,833	20
	LESS:							
21	Jurisdictional Sales not Subject to FAC	3,865,755	3,521,698	3,196,749	3,677,481	4,262,049	3,539,169	21
22	Intersystem Sales through MISO	654,010	43,345	414,800	34,131	761,484	1,323,376	22
23	Intersystem Sales other than MISO	27,657	9,578	28,734	(42,695)	487,984	44,178	23
24	Transmission Losses	99,703	54,405	130,836	19,241	235,869	322,084	24
25	Purchases over the Benchmark	485,313	243,226	23,187	231,828	1,829	10,173	25
26	Wind PPA Adjustment	-	-	-	-	-	68,647	26
27	TOTAL FUEL COSTS (F)	$38,579,734	$ 33,573,278	$ 30,063,724	$ 29,463,103	$ 27,200,410	$ 30,281,639	27
28	FUEL COST PER KWH (IN MILLS) F/S	**30.202**	**29.775**	**27.307**	**29.287**	**27.833**	**29.152**	28
29	FUEL COST PER KWH (IN DOLLARS) F/S	0.030202	0.029775	0.027307	0.029287	0.027833	0.029152	29

NORTHERN INDIANA PUBLIC SERVICE COMPANY

ACTUAL COST OF FUEL TO GENERATE ELECTRICITY AND
THE ACTUAL COST OF FUEL INCLUDED IN THE COST OF PURCHASED ELECTRICITY
FOR THE PERIOD OF JULY 2009 TO DECEMBER 2009 INCLUSIVE

2009

LINE NO.	DESCRIPTION	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	LINE NO.
	KWH SOURCE (000'S)							
1	Steam Generation	1,269,972	1,393,484	1,221,611	1,201,208	1,088,523	1,434,210	1
2	Nuclear Generation	-	-	-	-	-	-	2
3	Hydro Generation	1,930	1,690	1,274	2,651	3,768	5,428	3
4	Other Generation	388	357	668	345	281	669	4
5	Purchases through MISO	94,780	102,250	104,039	78,517	138,112	27,689	5
6	Purchased Power other than MISO	52,233	49,245	48,237	57,179	58,512	71,388	6
7	Power Received for Other Systems	186,366	172,816	181,458	116,063	150,380	160,274	7
	LESS:							
8	Jurisdictional Sales not Subject to FAC	36,001	9,260	8,409	11,930	12,413	13,099	8
9	Intersystem Sales through MISO	44,255	93,351	71,309	48,444	33,490	133,400	9
10	Intersystem Sales other than MISO	1	13	3	5	7	36	10
11	Power Transmitted for Other Systems	186,366	172,816	181,458	116,063	150,380	160,274	11
12	Energy Losses and Company Use	71,686	109,815	16,835	67,404	96,950	121,604	12
13	SALES (S)	1,267,360	1,334,587	1,279,273	1,212,117	1,146,336	1,271,245	13
	FUEL COST (F)							
14	Steam Generation	$ 33,434,511	$ 35,822,680	$ 31,405,540	$ 31,015,092	$ 28,652,739	$ 38,859,023	14
15	Nuclear Generation	-	-	-	-	-	-	15
16	Hydro Generation	-	-	-	-	-	-	16
17	Other Generation	35,952	34,228	42,173	39,800	22,907	70,811	17
18	Purchases through MISO	1,816,099	2,039,903	1,994,444	1,852,982	3,373,923	635,883	18
19	MISO Components of Cost of Fuel	1,022,535	635,461	950,891	(775,465)	(1,292,281)	1,812,952	19
20	Purchased Power other than MISO	820,096	938,599	680,810	1,004,582	885,065	1,126,637	20
	LESS:							
21	Jurisdictional Sales not Subject to FAC	996,783	257,156	213,252	311,452	330,997	395,077	21
22	Intersystem Sales through MISO	801,696	1,795,346	1,319,459	949,190	594,560	2,773,215	22
23	Intersystem Sales other than MISO	35,071	120,362	30,418	(57,373)	(66,244)	244,236	23
24	Transmission Losses	175,203	245,636	227,407	236,843	181,148	611,780	24
25	Purchases over the Benchmark	1,259	11,988	3,630	59	21,375	230	25
26	Wind PPA Adjustment	29,785	56,308	10,892	53,294	47,884	155,244	26
27	TOTAL FUEL COSTS (F)	$ 35,089,396	$ 36,984,075	$ 33,268,800	$ 31,643,526	$ 30,532,633	$ 38,325,524	27
28	FUEL COST PER KWH (IN MILLS) F/S	**27.687**	**27.712**	**26.006**	**26.106**	**26.635**	**30.148**	28
29	FUEL COST PER KWH (IN DOLLARS) F/S	0.027687	0.027712	0.026006	0.026106	0.026635	0.030148	29

NORTHERN INDIANA PUBLIC SERVICE COMPANY

ACTUAL COST OF FUEL TO GENERATE ELECTRICITY AND
THE ACTUAL COST OF FUEL INCLUDED IN THE COST OF PURCHASED ELECTRICITY
FOR THE PERIOD OF JANUARY 2010 TO JUNE 2010 INCLUSIVE

2010

LINE NO.	DESCRIPTION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	LINE NO.
	KWH SOURCE (000'S)							
1	Steam Generation	1,311,917	1,098,694	1,212,226	1,094,500	1,295,907	1,374,580	1
2	Nuclear Generation	-	-	-	-	-	-	2
3	Hydro Generation	5,959	4,780	7,451	5,387	6,968	6,728	3
4	Other Generation	463	645	439	336	392	2,941	4
5	Purchases through MISO	105,399	156,151	123,731	139,614	108,264	112,888	5
6	Purchased Power other than MISO	60,940	47,414	62,459	63,180	63,769	51,073	6
7	Power Received for Other Systems	202,153	177,787	131,546	154,738	100,724	172,165	7
	LESS:							
8	Jurisdictional Sales not Subject to FAC	10,445	12,322	9,106	22,250	51,027	39,405	8
9	Intersystem Sales through MISO	56,117	23,429	53,798	23,826	93,799	54,633	9
10	Intersystem Sales other than MISO	29	27	10	10	(4)	3	10
11	Power Transmitted for Other Systems	202,153	177,787	131,546	154,738	100,724	172,165	11
12	Energy Losses and Company Use	57,775	21,988	56,902	41,737	168,743	121,402	12
13	SALES (S)	1,360,312	1,249,918	1,286,490	1,215,194	1,161,735	1,332,767	13
	FUEL COST (F)							
14	Steam Generation	$ 35,907,663	$ 29,503,128	$ 30,933,123	$ 28,491,900	$ 33,384,859	$ 38,240,419	14
15	Nuclear Generation	-	-	-	-	-	-	15
16	Hydro Generation	-	-	-	-	-	-	16
17	Other Generation	59,053	72,953	43,050	31,166	35,385	226,245	17
18	Purchases through MISO	3,314,626	5,262,696	3,210,407	4,072,282	2,889,193	3,296,769	18
19	MISO Components of Cost of Fuel	845,167	572,389	306,885	5,001,480	4,593,725	2,832,157	19
20	Purchased Power other than MISO	1,082,792	840,226	1,105,199	2,307,172	1,302,722	906,056	20
	LESS:							
21	Jurisdictional Sales not Subject to FAC	350,619	356,811	241,044	706,326	1,486,602	1,368,415	21
22	Intersystem Sales through MISO	1,530,042	493,306	1,182,020	399,663	1,966,162	1,202,615	22
23	Intersystem Sales other than MISO	(205,737)	(25,319)	(51,551)	40,560	169,556	161,766	23
24	Transmission Losses	287,846	116,395	181,144	165,127	297,298	255,959	24
25	Purchases over the Benchmark	11,463	59,029	6,002	22,058	24,722	81,459	25
26	Wind PPA Adjustment	71,656	31,009	62,491	29,204	150,860	108,052	26
27	TOTAL FUEL COSTS (F)	$39,163,412	$ 35,220,161	$ 33,977,514	$ 38,541,062	$ 38,110,684	$ 42,323,380	27
28	FUEL COST PER KWH (IN MILLS) F/S	**28.790**	**28.178**	**26.411**	**31.716**	**32.805**	**31.756**	28
29	FUEL COST PER KWH (IN DOLLARS) F/S	0.028790	0.028178	0.026411	0.031716	0.032805	0.031756	29

NORTHERN INDIANA PUBLIC SERVICE COMPANY

ACTUAL COST OF FUEL TO GENERATE ELECTRICITY AND
THE ACTUAL COST OF FUEL INCLUDED IN THE COST OF PURCHASED ELECTRICITY
FOR THE PERIOD OF JULY 2010 TO DECEMBER 2010 INCLUSIVE

2010

LINE NO.	DESCRIPTION	JULY	AUGUST	SEPTEMBER	OCOTBER	NOVEMBER	DECEMBER	LINE NO.
	KWH SOURCE (000'S)							
1	Steam Generation	1,639,955	1,704,336	1,256,885	1,103,021	1,143,533	1,234,183	1
2	Nuclear Generation	-	-	-	-	-	-	2
3	Hydro Generation	3,441	1,961	1,418	1,109	1,895	2,797	3
4	Other Generation	3,801	4,289	505	391	356	768	4
5	Purchases through MISO	118,175	59,666	130,521	222,207	141,671	248,729	5
6	Purchased Power other than MISO	51,379	53,847	58,717	61,552	75,788	71,276	6
7	Power Received for Other Systems	198,142	244,962	200,712	106,021	133,473	150,143	7
	LESS:							
8	Jurisdictional Sales not Subject to FAC	43,271	45,386	74,559	80,886	61,312	83,002	8
9	Intersystem Sales through MISO	123,561	141,729	64,747	35,680	56,938	88,656	9
10	Intersystem Sales other than MISO	15	9	9	19	30	42	10
11	Power Transmitted for Other Systems	198,142	244,962	200,712	106,021	133,473	150,143	11
12	Energy Losses and Company Use	162,117	71,821	(74,576)	52,383	100,360	106,532	12
13	SALES (S)	1,487,787	1,565,154	1,383,307	1,219,312	1,144,603	1,279,521	13
	FUEL COST (F)							
14	Steam Generation	$ 44,356,108	$ 45,734,198	$ 32,823,571	$ 29,717,242	$ 30,401,330	$ 35,538,622	14
15	Nuclear Generation	-	-	-	-	-	-	15
16	Hydro Generation	-	-	-	-	-	-	16
17	Other Generation	305,398	318,865	37,671	24,817	33,360	60,969	17
18	Purchases through MISO	3,678,637	1,276,352	2,739,477	5,289,852	3,494,165	7,117,798	18
19	MISO Components of Cost of Fuel	2,139,193	1,229,073	963,584	157,049	1,344,172	(1,376,823)	19
20	Purchased Power other than MISO	883,054	1,086,105	1,247,917	1,330,062	1,608,133	1,323,961	20
	LESS:							
21	Jurisdictional Sales not Subject to FAC	1,443,243	1,274,199	2,233,664	2,462,765	1,762,395	2,685,112	21
22	Intersystem Sales through MISO	2,823,581	3,223,515	1,407,483	737,447	1,108,574	1,859,837	22
23	Intersystem Sales other than MISO	(35,895)	(121,889)	7,524	60,369	11,616	21,309	23
24	Transmission Losses	414,018	427,881	264,984	151,174	300,137	442,554	24
25	Purchases over the Benchmark	198,252	9,448	10,433	-	-	-	25
26	Wind PPA Adjustment	127,048	188,523	95,326	43,157	72,262	126,144	26
27	TOTAL FUEL COSTS (F)	$46,392,143	$ 44,642,916	$ 33,792,806	$ 33,064,110	$ 33,626,176	$ 37,529,571	27
28	FUEL COST PER KWH (IN MILLS) F/S	**31.182**	**28.523**	**24.429**	**27.117**	**29.378**	**29.331**	28
29	FUEL COST PER KWH (IN DOLLARS) F/S	0.031182	0.028523	0.024429	0.027117	0.029378	0.029331	29

NORTHERN INDIANA PUBLIC SERVICE COMPANY

ACTUAL COST OF FUEL TO GENERATE ELECTRICITY AND
THE ACTUAL COST OF FUEL INCLUDED IN THE COST OF PURCHASED ELECTRICITY
FOR THE PERIOD OF JANUARY 2011 TO JUNE 2011 INCLUSIVE

2011

LINE NO.	DESCRIPTION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	LINE NO.
	KWH SOURCE (000'S)							
1	Steam Generation	1,366,494	1,042,211	1,104,818	1,211,965	1,252,359	1,271,736	1
2	Nuclear Generation	-	-	-	-	-	-	2
3	Hydro Generation	3,180	4,477	7,865	6,913	7,876	5,776	3
4	Other Generation	659	816	668	348	991	2,516	4
5	Purchases through MISO	160,552	288,670	356,939	156,717	193,998	202,234	5
6	Purchased Power other than MISO	67,800	68,298	61,130	65,477	64,820	60,984	6
7	Power Received for Other Systems	274,768	148,137	132,944	159,967	122,902	158,902	7
	LESS:							
8	Jurisdictional Sales not Subject to FAC	112,771	116,470	145,397	39,675	48,144	36,651	8
9	Intersystem Sales through MISO	55,277	10,344	1,419	79,329	85,515	35,330	9
10	Intersystem Sales other than MISO	65	14	12	5	2	1	10
11	Power Transmitted for Other Systems	274,768	148,137	132,944	159,967	122,902	158,902	11
12	Energy Losses and Company Use	76,020	(1,855)	73,233	49,684	98,886	120,735	12
13	SALES (S)	1,354,552	1,279,499	1,311,359	1,272,727	1,287,497	1,350,529	13
	FUEL COST (F)							
14	Steam Generation	$ 38,119,841	$ 29,592,807	$ 32,079,769	$ 35,519,748	$ 36,099,776	$ 37,276,478	14
15	Nuclear Generation	-	-	-	-	-	-	15
16	Hydro Generation	-	-	-	-	-	-	16
17	Other Generation	56,466	61,799	52,606	31,369	73,113	202,046	17
18	Purchases through MISO	4,931,749	8,453,844	11,270,863	4,591,747	5,604,846	4,966,279	18
19	MISO Components of Cost of Fuel	(421,601)	995,233	948,552	1,061,804	1,718,175	1,280,623	19
20	Purchased Power other than MISO	1,323,908	1,568,011	1,239,481	1,483,507	1,685,690	1,161,841	20
	LESS:							
21	Jurisdictional Sales not Subject to FAC	3,755,689	3,898,762	4,908,597	1,288,656	1,690,525	1,244,368	21
22	Intersystem Sales through MISO	1,094,885	226,497	25,015	1,620,685	1,977,297	739,487	22
23	Intersystem Sales other than MISO	(81,758)	38,245	18,502	42,068	84,993	11,159	23
24	Transmission Losses	385,247	57,036	11,970	395,005	253,528	211,148	24
25	Purchases over the Benchmark	-	-	-	-	-	7	25
26	Wind PPA Adjustment	90,377	35,360	7,873	174,891	128,597	62,486	26
27	TOTAL FUEL COSTS (F)	$ 38,765,923	$ 36,415,794	$ 40,619,314	$ 39,166,870	$ 41,046,660	$ 42,618,612	27
28	FUEL COST PER KWH (IN MILLS) F/S	**28.619**	**28.461**	**30.975**	**$ 30.774**	**$ 31.881**	**$ 31.557**	28
29	FUEL COST PER KWH (IN DOLLARS) F/S	0.028619	0.028461	0.030975	0.030774	0.031881	0.031557	29

NORTHERN INDIANA PUBLIC SERVICE COMPANY

ACTUAL COST OF FUEL TO GENERATE ELECTRICITY AND
THE ACTUAL COST OF FUEL INCLUDED IN THE COST OF PURCHASED ELECTRICITY
FOR THE PERIOD OF JULY 2011 TO SEPTEMBER 2011 INCLUSIVE

2011

LINE NO.	DESCRIPTION	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	LINE NO.
	KWH SOURCE (000'S)							
1	Steam Generation	1,581,831	1,602,191	1,150,204	1,214,753	1,202,364	1,309,502	1
2	Nuclear Generation	-	-	-	-	-	-	2
3	Hydro Generation	4,434	1,756	1,084	3,322	4,526	9,323	3
4	Other Generation	6,472	3,396	1,162	480	2,010	309	4
5	Purchases through MISO	144,749	96,404	230,182	144,209	95,688	129,689	5
6	Purchased Power other than MISO	43,836	51,797	51,485	70,692	85,296	78,919	6
7	Power Received for Other Systems	194,175	270,107	168,001	112,537	155,400	150,633	7
	LESS:							
8	Jurisdictional Sales not Subject to FAC	26,537	20,550	28,237	41,817	39,186	58,276	8
9	Intersystem Sales through MISO	75,545	133,404	30,869	29,464	38,212	76,432	9
10	Intersystem Sales other than MISO	12	12	12	9	6	7	10
11	Power Transmitted for Other Systems	194,175	270,107	168,001	112,537	155,400	150,633	11
12	Energy Losses and Company Use	203,428	21,083	(71,081)	87,428	88,819	91,404	12
13	SALES (S)	1,475,800	1,580,495	1,446,080	1,274,738	1,223,661	1,301,623	13
	FUEL COST (F)							
14	Steam Generation	$ 47,257,977	$ 46,999,166	$ 32,126,036	$ 33,922,426	$ 31,934,809	$ 34,889,922	14
15	Nuclear Generation	-	-	-	-	-	-	15
16	Hydro Generation	-	-	-	-	-	-	16
17	Other Generation	487,852	228,284	82,076	35,371	116,432	21,278	17
18	Purchases through MISO	5,701,670	3,301,086	6,625,711	4,775,099	2,404,207	3,145,030	18
19	MISO Components of Cost of Fuel	3,627,301	2,296,225	1,283,640	546,351	825,715	1,644,811	19
20	Purchased Power other than MISO	500,937	823,601	815,277	1,491,764	1,957,039	1,818,971	20
	LESS:							
21	Jurisdictional Sales not Subject to FAC	1,078,949	683,368	898,155	1,393,886	1,226,413	1,769,064	21
22	Intersystem Sales through MISO	1,698,844	2,951,400	612,249	582,066	646,543	1,446,418	22
23	Intersystem Sales other than MISO	122,691	60,715	(60,193)	(8,223)	(18,740)	88,962	23
24	Transmission Losses	290,225	491,327	201,232	165,694	290,670	385,955	24
25	Purchases over the Benchmark	-	-	-	-	-	-	25
26	Wind PPA Adjustment	38,694	99,501	52,038	41,041	62,350	77,342	26
27	TOTAL FUEL COSTS (F)	$ 54,346,334	$ 49,362,051	$ 39,229,259	$ 38,596,547	$ 35,030,966	$ 37,752,271	27
28	FUEL COST PER KWH (IN MILLS) F/S	**$ 36.825**	**$ 31.232**	**$ 27.128**	**$ 30.278**	**$ 28.628**	**$ 29.004**	28
29	FUEL COST PER KWH (IN DOLLARS) F/S	0.036825	0.031232	0.027128	0.030278	0.028628	0.029004	29

NORTHERN INDIANA PUBLIC SERVICE COMPANY
Comparison of Current Filing and Prior Approved Fuel Cost Factor
Cause No. 38706-FAC94 and Cause No. 38706-FAC 93 Revised

		CONTRIBUTION TO FUEL COST ADJUSTMENT (MILLS/KWH)			
LINE NO.		CAUSE NO. 38706-FAC94	CAUSE NO. 38706-FAC93 Revised	DIFFERENCE	LINE NO.
1	Fuel Cost excluding Variance	29.884	32.596	(2.712)	1
2	Fuel Cost Variance Adjustment	(1.873)	0.977	(2.850)	2
3	Interruptible Credit Recovery	0.027	0.000	0.000	3
4	Interruptible Credit Recovery Variance Adjustment	0.000	0.000	0.000	4
5	Tax included in calculation	(0.011)	0.075	(0.086)	5
6	Total Fuel Cost	28.027	33.648	(5.621)	6
7	LESS: Base Cost in Base Rates	28.729	28.729	0.000	7
8	TOTAL FUEL COST FACTORS	(0.702)	4.919	(5.621)	8

CAUSE NO. 38706-FAC94
EXHIBIT 1-D

NORTHERN INDIANA PUBLIC SERVICE COMPANY

COMPARISON OF CURRENT FILING AND PRIOR APPROVED FUEL COST FACTOR

CAUSE NO. 38706-FAC94 AND CAUSE NO. 38706-FAC93

		ESTIMATED COST		MWH		UNIT COST (MILLS/KWH)		
LINE NO.	SOURCE	CURRENT FILING CAUSE NO. 38706-FAC94	PRIOR FILING CAUSE NO. 38706-FAC93	CURRENT FILING CAUSE NO. 38706-FAC94	PRIOR FILING CAUSE NO. 38706-FAC93	CURRENT FILING CAUSE NO. 38706-FAC94	PRIOR FILING CAUSE NO. 38706-FAC93	LINE NO.
1	STEAM GENERATION	$ 109,127,227	$ 118,019,121	3,888,687	3,965,655	28.063	29.760	1
2	NUCLEAR GENERATION	-	-	0	-	-	-	2
3	HYDRO GENERATION	-	-	17,349	16,541	-	-	3
4	OTHER GENERATION	190,950	101,411	3,566	1,466	53.547	69.156	4
5	PURCHASES THROUGH MISO	13,634,340	18,414,444	619,746	557,285	22.000	33.043	5
6	MISO COMPONENTS OF COST OF FUEL	3,951,708	3,228,588	66,051	-	59.828	-	6
7	PURCHASED POWER OTHER THAN MISO	3,245,226	3,027,476		61,591	-	49.154	7
	LESS:							
8	ENERGY LOSSES AND COMPANY USE		-	227,734	233,263	-	-	8
9	INTERSYSTEM SALES THROUGH MISO	8,329,604	6,888,359	298,528	201,325	27.902	34.215	9
10	INTERSYSTEM SALES OTHER THAN MISO	-	-	-	-	-	-	10
11	JURISDICTIONAL SALES NOT SUBJECT TO FAC	-	4,173,004	-	133,800	-	31.188	11
12	WIND PPA ADJUSTMENT	217,638	232,845	-	-	-	-	12
13	PURCHASE POWER BENCHMARK ADJUSTMENT	-	-	-	-	-	-	13
14	TOTAL	$ 121,602,208	$ 131,496,832	4,069,137	4,034,150	29.884	32.596	14

VERIFIED DIRECT TESTIMONY OF RONALD G. PLANTZ

Q1. Please state your name, business address and title.

A1. My name is Ronald G. Plantz. My business address is 801 East 86th Avenue, Merrillville, Indiana 46410. I am employed by NiSource Corporate Services Company ("NCS") and my current position is Controller of Northern Indiana Public Service Company ("NIPSCO" or the "Company").

Q2. Please describe your educational and employment background.

A2. I hold a Bachelor of Science degree from West Virginia State College and an Executive Master of Business Administration degree from West Virginia University. I am a Certified Public Accountant and a member of American Institute of Certified Public Accountants. In August, 1986, I was hired by the Columbia Energy Group Service Corporation as the Audit Manager for the Pipeline Segment. I held that position for three years before moving into the finance department. I remained there until the merger of Columbia Gas with NiSource on November 1, 2000. Following the merger, I became the Assistant Controller for NiSource, reporting to the Vice President and Controller. I was responsible for consolidating the financial statements submitted by all NiSource companies, including NIPSCO. I held that position until accepting my current assignment as Controller of NIPSCO on May 1, 2011.

Q3. What are your responsibilities as Controller of NIPSCO?

A3. As Controller, my principal responsibilities include providing accurate and timely completion of Generally Accepted Accounting Principles ("GAAP") financial statements and managerial reports on a monthly and quarterly basis.

Q4. Are you familiar with the Company's Verified Petition, including the exhibits attached thereto, initiating this proceeding, a copy of which has been marked <u>Petitioner's Exhibit No. 1-A</u>?

A4. Yes.

Q5. What is the purpose of your direct testimony in this proceeding?

A5. The purpose of my testimony is to present evidence regarding the return earned by NIPSCO during the 12-month period ending December 31, 2011 ("Reconciliation Period") and to sponsor testimony and exhibits with reference to Ind. Code § 8-1-2-42.3. I also offer evidence for the purpose of the expense offset test of Ind. Code § 8-1-2-42(d)(2) to show that increases in fuel expense from the test-year levels considered in Cause No. 43969, the last proceeding in which Petitioner's basic rates and charges for electric service were approved, have not been offset by decreases in other operating expenses.

Q6. Are you sponsoring any exhibits in this Cause?

A6. I am sponsoring Petitioner's Exhibit Nos. 2-A through 2-C, all of which were prepared by me or under my direction and supervision.

Q7. Please describe Petitioner's Exhibit Nos. 2-A and 2-B.

A7. Petitioner's Exhibit No. 2-A is a comparison of operating income. It shows that the Company's fuel expenses in the Reconciliation Period were $71,636,521 [Petitioner's Exhibit No. 2-A, Page 1, Line 15, Column D] above the levels approved in the Commission's December 21, 2011 Order in Cause No. 43969 ("43969 Order"), the last proceeding in which Petitioner's basic rates and charges for electric service were approved and that those increases were not offset by decreases in other operating expenses. Petitioner's Exhibit No. 2-B compares the operating income for the Reconciliation Period of $136,479,509 [Petitioner's Exhibit No. 2-A, Page 1, Line 14b, Column C] with the authorized amount of $188,872,242 [Petitioner's Exhibit No. 2-A, Page 1, Line 14b, Column B]. Actual ECRM operating income [Petitioner's Exhibit No. 2-A, Page 1, Line 14a, Column B] is $0 because there are no realized revenues eligible at December 31, 2011. Given this shortfall from the return authorized in the 43969 Order, there are no "excess" earnings to be shared with NIPSCO ratepayers under Ind. Code § 8-1-2-42.3, as reflected in Petitioner's Exhibit No. 2-B.

Q8. Please describe Petitioner's Exhibit No. 2-C.

A8. Petitioner's Exhibit No. 2-C shows the historical earned returns for the "Relevant Period," defined in accordance with Ind. Code § 8-1-2-42.3. Pursuant to the Stipulation and Settlement Agreement approved by the 43969 Order, NIPSCO's recent electric base rate case, NIPSCO has reset the amount of accumulated negative earnings commonly referred to as the "earnings bank" to $200,000,000. The amount of $52,392,733 [Petitioner's Exhibit No. 2-C, Line 1, Column H] of under-earnings in the current filing is credited to this accumulated negative earnings to total $252,392,733.

Q9. For purposes of Petitioner's Exhibit Nos. 2-A, 2-B and 2-C, has the Company modified its authorized net operating income to account for the

return realized by the Company through its ECRM?

A9. No. The 43969 Order approved rates that included recovery of all environmental projects upon which a revenue was earned and recovered through NIPSCO's ECRM during the twelve months ended December 31, 2011. Therefore, the Company has added no dollars (Petitioner's Exhibit No. 2-A, Page 1, Line 14a, Column B) to its authorized net operating income shown in Petitioner's Exhibit Nos. 2-A, 2-B and 2-C.

Q10. Has the Company modified Petitioner's Exhibit No. 2-A to reflect separately the current recovery of Operations, Maintenance and Depreciation expenses realized by the Company through application of its Environmental Expense Recovery Mechanism ("EERM")?

A10. Yes. Pursuant to the Commission's Order in Cause No. 42150, the EERM is a tracker for the expenses related to the operation, maintenance and depreciation of Qualified Pollution Control Property projects placed in service and approved for recovery under the EERM mechanism. Petitioner's Exhibit No. 2-A has been modified to reflect the operation, maintenance and depreciation expenses that match the revenues as a result of application of the EERM factors.

Q11. Is NIPSCO required to refund any of the FAC revenues collected during the twelve months ended December 31, 2011?

A11. No. Fuel charges collected during the Reconciliation Period were collected subject to refund, pending knowledge of compliance with the statutory financial tests set forth in Ind. Code 8-1-2-42(d) for that period. As the Company's records now show, both tests were met during the Reconciliation Period. Therefore, the conditions that made the collection of revenues during the Reconciliation Period "subject to refund" pending knowledge of compliance with the statutory financial tests under Ind. Code 8-1-2-42(d) in the Commission Orders in Cause Nos. 38706-FAC 89 through FAC 93 did not come to pass.

Q12. Have the amounts invoiced by MISO as a result of its energy market been reflected on the books and records of the Company?

A12. Yes. In addition, in accordance with Generally Accepted Accounting Principles, amounts recorded in NIPSCO's books and records include estimates where actual figures are not available in order to most accurately reflect costs incurred in the period. In most months, an estimate is used for the last several days of the MISO charges since those days have not been invoiced.

Q13. Does this conclude your prepared direct testimony?

A13. Yes.

VERIFICATION

I, Ronald G. Plantz, Controller of Northern Indiana Public Service Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Ronald G Plantz

Ronald G. Plantz

Date: January 31, 2012

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Comparison of Operating Income
Twelve Months Ended December 31, 2011
With Allowed IURC Pro Forma Operating Income From Cause No. 43969

	Column A		Column B		Column C	Column D
			Cause #43969			
Line No.	Description		Allowed IURC Pro Forma		Total Electric Actual	
1	Operating Revenues	$	1,401,000,000	$	1,428,474,288	
2	Operating Expenses					
3	Operation & Maintenance					
4	Fuel & Purchased Power		461,751,166		533,387,687	
5	Other Operations		259,988,297		284,263,349	
6	Maintenance		115,956,190		121,988,527	
6a	EERM O & M				12,805,427	
7	Total O & M	$	837,695,653	$	952,444,990	
8	Depreciation & Amortization		226,893,498		198,102,730	
8a	EERM Depreciation & Amortization				14,146,394	
9	Taxes Other Than Income		57,823,318		56,502,220	
10	Total Operating Expenses					
11	Excluding Income Taxes	$	1,122,412,469	$	1,221,196,333	
12	Income Taxes		89,715,289		70,798,446	
13	Total Operating Expense	$	1,212,127,758	$	1,291,994,780	
14	Operating Income Before ECRM	$	188,872,242			
14a	Actual ECRM Operating Income(See Page 1A)		-			
14b	Oper. Inc. Including ECRM and Opp. Sales	$	188,872,242	$	136,479,509	

Summary of Increase in Operating Expenses Applicable To IURC Jurisdiction

Line No.	Description		Twelve Months Ended June 30, 2010 (Col. B)		Twelve Months Ended December 31, 2011 (Col. C)		Increase / (Decrease)
15	Fuel Expenses (Line 4)	$	461,751,166	$	533,387,687	$	71,636,521
16	Total Operating Expenses						
17	Excluding Fuel	$	750,376,592	$	758,607,092	$	8,230,500

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Calculation of ECRM Operating Income
Twelve Months Ended December 31, 2011

1	Booked Revenue eligible for recovery 05/11-10/11	$ -
2	Revenue Conversion Factor through10/11	1.507841
3	Operating Income (line1/line2)	$ -
4	Booked Revenue eligible for recovery 11/11- 12/11	$ -
5	Revenue Conversion Factor through 04/12	1.509113
6	Operating Income (line4/line5)	$ -
7	Booked Revenue elibible for recovery 1/11 - 04/11	$ -
8	Revenue Conversion Factor through 04/11	1.546709
9	Operating Income (line7/line8)	$ -
10	Total ECRM Operating Income eligible for recovery	$ -

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Statement of Rate of Return
Twelve Months Ended December 31, 2011
Approved Original Cost Rate Base Cause No. 43969

	Column A		Column B
			Per Final Order Cause No. 43969
Line No.	Description		Total
1	Net Electric Plant In Service	$	2,581,447,813
2	Material & Supplies		58,224,978
3	Electric Production Fuel		52,823,583
4	Deferred Depreciation and Carrying Charges		13,409,677
5	Total Original Cost Rate Base	$	2,705,906,051
6	Operating Income (Exh. No. 2-A, Pg. 1, Col.C , Line 14b)	$	136,479,509
7	Rate of Return		5.04%
8	Operating Income Allowed Per Cause 43969 (Exh. No. 2-A, Pg. 1, Col. B, Line 14b)	$	188,872,242
9	Rate of Return		6.98%

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC Electric Earnings Test
December 31, 2011

	Column A	Column B	Column C	Column D	Column E	Column F	Column G	Column H	Column I
Line no.	Twelve Months Ended	Cause No.	IURC Approval Date	Authorized Return (1)	Actual Return	Over/(Under) Earning	Portion of Earnings Subject to Sharing	Portion of Earnings Credited to Column I	Cumulative Amount (1)
						(Col.E - Col.D)			(Sum of Col. H)
1	December 31, 2011	38706-FAC 94	Pending	$ 188,872,242	$ 136,479,509	$ (52,392,733)	$ -	$ (52,392,733)	$ (252,392,733)
2	Per Final Order Cause No. 43969 Dated December 21, 2011							(200,000,000)	(200,000,000)

Note:

(1) Cumulative amount reset to $200,000,000 according to final order Cause No. 43969 Dated December 21, 2011

VERIFIED DIRECT TESTIMONY OF DANIEL T. WILLIAMSON

Q1. Please state your name, business address and title.

A1. My name is Daniel T. Williamson. I am the Executive Director of Energy Supply and Trading for Northern Indiana Public Service Company ("NIPSCO" or "Company"). My business address is 1500 165th Street, Hammond, Indiana 46320.

Q2. Please describe your educational and employment background?

A2. I graduated in 1997 from Purdue University with a Bachelors Degree in Business Management. I began my employment with NiSource in 1997 in an Associate Training Program and during that time began working for NESI Power Marketing. There I worked as a power scheduler and hourly power trader. In 1998, I took a position as an Energy Resource Engineer at NIPSCO optimizing electric generation. I began working for Energy USA/TPC as an Energy Trader in approximately 1999 and spent 5 years in this position. In 2004, I took a position back at NIPSCO as an Energy Trader. In December 2008, I became Manager of Energy Trading with responsibility over NIPSCO gas and power trading. In November 2010, I assumed my current position.

Q3. What are your responsibilities as Executive Director, Energy Supply and Trading?

A3. As Executive Director, Energy Supply and Trading, I am responsible for various aspects of the electric and gas energy supply responsibilities for NIPSCO. This includes oversight of the following groups: Gas Control, Electric Dispatch, Electric and Gas Resource Planning, Energy Trading, Market Research, MISO Market Settlements Group, and Gas Scheduling/Accounting.

Q4. Are you familiar with the Company's Verified Petition, including the exhibits attached thereto, initiating this proceeding, a copy of which has been marked <u>Petitioner's Exhibit No. 1-A</u>?

A4. Yes.

Q5. What is the purpose of your testimony in this proceeding?

A5. The purpose of my testimony is to (i) support the reasonableness of NIPSCO's purchase of electric energy from other utilities and MISO; (ii) describe NIPSCO's inclusion of its wind purchases in this FAC and explain what NIPSCO is doing with Renewable Energy Credits associated with those wind purchases; (iii) describe NIPSCO's coordination with

MISO's energy market operations, which began on April 1, 2005, and its applicable costs, (iv) describe NIPSCO's coordination with MISO's ancillary services market ("ASM"), which began January 6, 2009, and its applicable costs; (v) provide an overview of the MISO settlements process for the charges and credits that NIPSCO incurs as a result of its participation in the MISO energy and operating reserve markets; (vi) support the incorporation of the operational changes of MISO energy and operating reserve markets into NIPSCO's estimate for this FAC filing; and (vii) describe application of the Purchased Power Benchmark approved in the Indiana Utility Regulatory Commission's ("Commission") August 25, 2010 Order in Cause No. 43526 ("43526 Order") and the RSG Benchmark approved in the Commission's June 30, 2009 Order in Cause No. 43665 ("43665 Order").

Q6. What exhibits are you sponsoring?

A6. I am sponsoring Petitioner's Exhibit Nos. 3-A and 3-B, both of which were prepared by me or under my direction and supervision.

Q7. Please describe Petitioner's Exhibit Nos. 3-A and 3-B.

A7. Petitioner's Exhibit No. 3-A is the calculation of the daily purchased power benchmark price. Petitioner's Exhibit No. 3-B is the calculation of the revenue sufficiency guarantee ("RSG") benchmark price.

Cost Variances

Q8. How did the Company's fuel costs in October, November and December 2011 compare with the Company's estimates for those months?

A8. The total actual Fuel Cost Difference for the sum of October, November and December 2011 was $9,307,903 less than the estimate. (Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5, page 4 of 10, line 27).

The October 2011 estimate of total fuel cost subject to FAC was $1,462,019 more than actual (Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5, page 1 of 10, line 27) driven mostly by a decrease in actual (as compared to the forecast) purchase power volume of $2,090,222 (Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5, page 1 of 10, lines 18 & 20), a larger actual credit (as compared to the forecast) associated with Intersystem Sales through MISO of $630,416 (Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5, page 1 of 10, lines 22 & 24), and an increase in actual (as compared to the forecast) Jurisdictional Sales not Subject to FAC of $563,800 (Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5, page 1 of 10, line 21). These include costs associated with special contracts for retail customers not subject to FAC. This was offset by an increase in actual (as compared to the forecast) fuel usage and fuel cost for NIPSCO generation of $2,127,835 (Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5, page 1 of 10, lines 14 & 17). The average cost of actual purchased power was 10.9% lower than the estimate.

The November 2011 estimate of total fuel cost subject to FAC was $4,211,226 more than actual (Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5, page 2 of 10, line 27) driven mostly by a decrease in actual (as compared to the forecast) fuel usage and fuel cost for NIPSCO generation of $2,183,617 (Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5, page 2 of 10, lines 14 & 17), a decrease in actual (as compared to the forecast) purchase power volume of $871,153 (Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5, page 2 of 10, lines 18 & 20), and a larger actual credit (as compared to the forecast) associated with Intersystem Sales through MISO of $752,536 (Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5, page 2 of

10, lines 22 & 24). The average cost of actual purchased power was 29.1% lower than the estimate.

The December 2011 estimate of total fuel cost subject to FAC was $3,634,658 greater than actual (Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5, page 3 of 10, line 27) driven mostly by a decrease in actual (as compared to the forecast) fuel usage and fuel cost for NIPSCO generation of $4,909,988 (Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5, page 3 of 10, lines 14 & 17), and an increase in actual (as compared to the forecast) Jurisdictional Sales not Subject to FAC of $943,819 (Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5, page 3 of 10, line 21). These include costs associated with special contracts for retail customers not subject to FAC. This was offset by an increase in actual (as compared to the forecast) purchase power volume of $875,047 (Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5, page 3 of 10, lines 18 & 20), a higher actual MISO Components Cost of Fuel of $825,361 (Exhibit B, Schedule 5, page 3 of 10, line 19), and a decrease in the actual credit (as compared to the forecast) associated with Intersystem Sales through MISO of $685,045 (Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5, page 3 of 10, lines 22 & 24). The average cost of actual purchased power was 24.2% lower than the estimate.

Purchased Power

Q9. Are you familiar with the costs associated with NIPSCO's purchase of electric energy from other utilities and MISO?

A9. Yes.

Q10. Are any purchases from the Barton and/or Buffalo Ridge Wind Farms included in this FAC, either in actual and/or projected fuel costs?

A10. Yes. Wind purchases are included in NIPSCO's actual and projected fuel costs. Pursuant to the Commission's July 24, 2008 Order in Cause No. 43393 ("43393 Order"), NIPSCO began receiving power and seeking recovery of purchase power costs from Barton on April 10, 2009 and Buffalo Ridge on April 15, 2009. For the months of October, November and December 2011, NIPSCO received 24,768 MWhs, 34,286 MWhs and 30,747 MWhs, respectively.

Q11. Where are these purchases shown in your schedules in this proceeding?

A11. The actual purchases are included in Purchased Power other than MISO on Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5, Pages 1 through 4, Lines 6 and 20. The projected purchases are included in Purchased Power other than MISO on Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 1, Lines 6 and 18. The details of these power purchases are included in the confidential workpapers provided to the other parties.

Q12. Please explain the Renewable Energy Credits associated with the energy NIPSCO purchases under the wind purchased power agreements.

A12. Each megawatt of power generated from a qualified resource can be awarded a renewable energy credit ("REC"). Many state jurisdictions require sellers of renewable power to have such RECs to certify that the source is in fact a qualified renewable resource. As no national standard currently exists, each jurisdiction has set its own regulations as to how to qualify and account for these RECs. As each megawatt is sold by the qualified resource, the associated REC is sold to the buyer or is retired to prevent double counting. NIPSCO receives RECs associated with the power it purchases from the Barton and Buffalo Ridge Wind Farms which qualify under a coalition of Midwestern states, not including Indiana, and are tracked by the Midwest Renewable Energy Tracking System ("M-RETS").

Q13. Please explain how NIPSCO has used the RECs to maximize the value to its customers.

A13. Since Indiana does not currently have regulations that guide the certification and accounting for RECs, NIPSCO has held the RECs on account with M-RETS due to their relatively low market value and in the event that the State of Indiana were to approve a renewable energy standard that would consider NIPSCO's current RECs as eligible. The Indiana General Assembly recently passed Senate Bill 251, which includes a voluntary renewable energy standard and the Commission conducted a rulemaking process to implement it. NIPSCO monitored the results of that legislation and rulemaking and is making changes in the way RECs are utilized.

Q14. Has NIPSCO's treatment of RECs changed since FAC93?

A14. Yes.

Q15. Would NIPSCO consider other options for the treatment of RECs in the future?

A15. Yes. After a review of Senate Bill 251, NIPSCO believes that it will be in the best interests of its customers to sell RECs that it acquires. NIPSCO will continue to monitor any potential future legislation that would consider NIPSCO's RECs as eligible to meet state renewable energy standards and will make appropriate changes as necessary.

Currently, RECs are thinly traded in the over-the-counter market and their values can vary greatly due to the patchwork of jurisdictional requirements. NIPSCO plans to offer RECs to the market when it acquires a minimum of 50,000 RECs, which is the standard RECs contract. This will spread the sales of RECs over multiple time periods throughout the year.

Q16. How else do NIPSCO's wind purchases impact this proceeding?

A16. Pursuant to the 43393 Order, NIPSCO is crediting any off-system sales profits created by its Wind Purchase Power Agreements ("PPAs") with Barton and Buffalo Ridge. This credit is included in Wind PPA Adjustment on Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5, Pages 1 through 4, Line 26.

Q17. Has NIPSCO incorporated a projected Wind PPA Adjustment in its filings?

A17. Yes. In prior FAC filings, NIPSCO did not forecast the Wind PPA Adjustment and only included the actual Wind PPA Adjustment in the reconciliation process. Beginning in FAC93, NIPSCO has incorporated a projected Wind PPA Adjustment based on the average of actual "Wind PPA Adjustment" incurred for the twelve month period of January 2011 through December 2011. The actual Wind PPA Adjustment is included on Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5, Pages 1 through 4, line 26. The projected Wind PPA Adjustment is included on Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 1, Line 22.

Q18. Does NIPSCO expect to buy any firm, long-term "Purchased Power" (a long term purchase is a purchase of power for greater than 12 consecutive months) during the estimated months of April, May and June 2012?

A18. No.

Q19. Did NIPSCO purchase any monthly blocks of power prior to the start of the months being reconciled in this filing?

A19. No.

Q20. What impact did the availability of the Sugar Creek Generating Station ("Sugar Creek") have on purchased power?

A20. The dispatch of Sugar Creek decreased the need for purchased power from MISO during times of higher Locational Marginal Pricing ("LMP") thereby decreasing both the volume and the average cost of purchased power. The dispatch of Sugar Creek acts as an internal resource option with lower fuel costs that hedge against higher cost energy purchases when they occur and helps reduce the volatility of purchase power costs. Sugar Creek was dispatched in MISO 7 days in October, 23 days in November and 27 days in December 2011.

Q21. What is included in "Other Generation" as shown on Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5, Pages 1 through 4, Lines 4 and 17?

A21. "Other Generation" includes the fuel costs associated with NIPSCO's combustion turbines.

Q22. Did NIPSCO make reasonable decisions under the circumstances that were known at the time that it estimated its production and purchase power costs for the period of April through June 2012?

A22. Yes, in my judgment it has. NIPSCO completed its estimate for this FAC filing on January 18, 2012 using its production cost modeling system, PROMOD, and made reasonable decisions under the circumstances known at that point in time including the dispatch of Sugar Creek and wind purchases.

Q23. Has NIPSCO made every reasonable effort to generate and/or purchase power so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible?

A23. Yes.

MISO

Q24. Are you generally familiar with the operations of MISO?

A24. Yes. I am involved in an oversight role with NIPSCO's MISO energy and operating reserves markets.

Q25. What are your responsibilities in that regard?

A25. My responsibilities include an oversight role for the following: dispatching into MISO, offering of NIPSCO's generation to MISO energy and ASM markets, and bidding in NIPSCO's load requirements.

Q26. Please describe the fuel-related MISO charges and credits that NIPSCO is seeking to recover in this proceeding.

A26. NIPSCO proposes to recover in this FAC filing the fuel-related charges and credits assigned to NIPSCO by MISO and attributable to NIPSCO's retail electric customers in accordance with the Commission's June 1, 2005 Order in Cause No. 42685 ("42685 Order") and the Commission's Phase II Order in Cause No. 43426 ("43426 Order"). NIPSCO also proposes to recover the applicable RSG charges in accordance with the 43665 Order.

Q27. Is NIPSCO's proposed recovery of costs incurred in October, November and December 2011 consistent with your understanding of the 42685, 43426 and 43665 Orders?

A27. Yes.

Q28. Are you familiar with MISO's process to settle energy and operating reserve market charges and credits with NIPSCO?

A28. Yes.

Q29. Has NIPSCO verified the accuracy of the fuel-related charges and credits from MISO that are reflected in this FAC filing?

A29. Yes.

Q30. Please describe MISO's settlements process to settle energy and operating reserve market charges and credits as they apply to NIPSCO.

A30. For each operating day, MISO sends NIPSCO a settlement statement that sets forth Day Ahead market charges and credits, Real Time market charges and credits, charges and credits related to the Financial Transmission Rights ("FTRs") market, and charges and credits related to ASM. The settlement statements set forth each charge type along with the underlying billing determinants used to calculate the charge. MISO's settlements process is described in detail in MISO's Business Practices Manual for Market Settlements.[1]

Q31. What is the timeline for issuance of MISO settlement statements?

A31. Charges and credits for the Day Ahead market, the Real Time market and FTRs are settled for each operating day a minimum of four times. MISO issues a preliminary settlement statement (commonly referred to as the S7) for an operating day seven calendar days after that operating day. Market participants are expected to verify the accuracy of the S7 prior to the issuance of the second settlement statement, which is issued 14

[1] http://www.midwestmarket.org/publish/Folder/20f443_ffd16ced4b_-7fe50a3207d2?rev=6

calendar days after the operating day (commonly referred to as the S14). The S14 fully recalculates the charges and credits for the applicable operating day and displays differences between the charges and credits as calculated on the applicable S7. Invoices for an operating day's charges and credits are not issued until completion of the S14. Additional settlement statements are issued 55 and 105 days after the operating day that again fully recalculate an operating day's charges and credits to reflect updates to meter data submitted by market participants, resolved disputes and other adjustments. Those settlement statements are referred to as the S55 and S105, respectively. As mentioned above, NIPSCO verifies the accuracy of the charges and credits set forth on all of the settlement statements described above that are applicable to NIPSCO and, if necessary, disputes any errors pursuant to MISO's dispute resolution procedures.

Q32. How does NIPSCO verify the accuracy of the MISO settlement statements?

A32. NIPSCO utilizes sophisticated software tools of PCI GenManager to perform daily shadow settlement, to essentially "shadow" MISO's settlements systems, and verify MISO settlement statements and invoices. Using those tools, analysts in NIPSCO's settlements group are able to download MISO settlements data, perform a detailed comparison by charge type, and charge component against NIPSCO's internal data. The tools highlight discrepancies that are immediately corrected or disputed depending on the source of the error. For charges and credits that are based solely on NIPSCO data, analysts can identify errors at the lowest level of granularity.

Q33. Are there any charges or credits relevant to this proceeding currently in dispute?

A33. No.

Q34. How will the resolution of disputed charges and credits be reflected in future FAC filings?

A34. Given the extended period of the MISO settlements process, adjustments to charges and credits incurred during a particular period may not be known or reflected in NIPSCO's books and records at the time of the quarterly FAC filing for that period. Indeed, adjustments could occur even after the S105 is issued. Consequently, it would be impractical to retroactively apply the effects of settlement statement adjustments to past customer bills. For those reasons, NIPSCO proposes that settlement statement adjustments that affect the cost of fuel or the cost of fuel of purchased power be reflected as soon as practicable in a subsequent FAC filing.

Q35. Is NIPSCO's proposed recovery of ASM charges and credits consistent with your understanding of the 43426 Order?

A35. Yes.

Q36. In general, what is NIPSCO's experience thus far with the ASM?

A36. MISO launched its ASM on January 6, 2009 and, to my knowledge, ASM has generally functioned without any major issue. NIPSCO's generators have been following real time signals as directed by MISO with minimal issues. Day Ahead and Real Time market clearing prices (MCP) for Regulation, Spinning and Supplemental Reserves appear to be at reasonable levels consistent with market conditions. Between July 1, 2011 and September 30, 2011, the average ASM prices per megawatt hour were as follows:

Month	Regulation	Spinning	Supplement
October 2011	$0.0777	$0.0493	$0.0193
November 2011	$0.0730	$0.0307	$0.0151
December 2011	$0.0596	$0.0240	$0.0161

Q37. Is NIPSCO's proposed recovery of Day-Ahead and Real-Time RSG distribution amounts consistent with your understanding of the 43665 Order?

A37. Yes.

Q38. What are RSG payments and charges?

A38. RSG payments are make-whole payments that MISO makes to generators that do not earn sufficient real-time energy revenues to cover start-up and no-load costs. MISO recovers these RSG payments from participants in its day-ahead and real-time energy markets who contribute to RSG payments by submitting bids and offers that affect generation unit commitment, or have deviations from their schedules that affect the commitment of generation.

Q39. Please summarize the RSG rate calculation problem first identified by NIPSCO in FAC78.

A39. In FAC78, NIPSCO noted that it had disputed certain Real Time Revenue Sufficiency Guarantee Make Whole Payments charges or credits assessed by MISO. NIPSCO proposed that if it received any settlement statement adjustments relating to RSG charges or credits, it would include the adjustments in its next FAC filing.

Q40. Has there been any resolution to the Federal Energy Regulatory Commission ("FERC") proceedings concerning the RSG rate calculation problem first addressed in FAC78?

A40. No. NIPSCO's request for rehearing of the FERC's May 6, 2009 order in Docket No. EL07-86 is still pending. That order upheld its earlier decision granting NIPSCO's complaint, but largely reversed its directive requiring MISO to pay refunds and collect surcharges, on equitable grounds. First Rehearing Order, 117 FERC 61, 113 at P. 92-96. FERC affirmed the refund and surcharge requirement only for those transactions for a period that did not affect the FAC. Since NIPSCO's filing of testimony in FAC91, FERC has not issued any orders which provide resolution on the RSG rate calculation issue first addressed in FAC78.

Q41. How has the inclusion of Sugar Creek into the NIPSCO portfolio impacted RSG Make Whole Payments ("MWP")?

A41. NIPSCO has received RSG MWP due to MISO's reliability assessment commitments of Sugar Creek and NIPSCO combustion turbines. These payments are intended to keep Sugar Creek, as well as any other generators that are committed, whole relative to their offers over the course of the operating day when MISO commits such units for reliability. As these payments are tied to specific generators, NIPSCO receives payments from MISO spread evenly across the actual number of operating hours for that generator for that operating day, and then allocates each hour's payment amount on an hour-by-hour, prorated basis per the allocation of that particular generator between native load and off system sales.

Q42. How is the Company estimating "MISO Components of Cost of Fuel"?

A42. NIPSCO reviews the "MISO Components of Cost of Fuel" to determine a reasonable estimate to include in its FAC filings. In this filing, NIPSCO has included an updated estimate of "MISO Components of Cost of Fuel" in the amount of $1,317,236 per month. Petitioner's Exhibit No. 1-A,

Exhibit B, Schedule 1, Line 17. In NIPSCO's last FAC filing, NIPSCO included an estimate of "MISO Components of Cost of Fuel" in the amount of $1,076,196. The estimate contained in this filing represents an approximate 22% increase from the last FAC filing. The estimate in this proceeding is based on the average of actual "MISO Components of Cost of Fuel" incurred for the twelve month period ending December 31, 2011. These costs are included in "MISO Components of Cost of Fuel" on Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 2.

BENCHMARKS

Q43. Please describe the Purchased Power Benchmark approved in the 43526 Order.

A43. In the 43526 Order, the Commission approved a "Benchmark" triggering mechanism for the judgment of the reasonableness of purchased power costs. Each day, on a prospective basis, a Benchmark is established based upon a generic gas turbine ("GT"), using a generic GT heat rate of 12,500 btu/kwh using the Platt's Gas Daily Midpoint price for Chicago City Gate, plus a $0.17/MBtu gas transport charge for a generic gas-fired GT, which is then utilized to determine whether the Company incurred any Purchase Power Non-Recoverable amounts. The Commission did not order any change in the Purchased Power Benchmark in its December 21, 2011 Order in Cause No. 43969. The Purchased Power Daily Benchmarks for this reconciliation period are set forth in <u>Petitioner's Exhibit No. 3-A</u>.

Q44. Are all purchased power transactions subject to the Purchased Power Daily Benchmark?

A44. No. Purchased power transactions subject to the Purchased Power Daily Benchmark are those power purchases that are used to serve FAC load (excluding backup and maintenance contracts) as determined by NIPSCO's RCA system, including bilateral purchases for load and MISO Day Ahead and Real Time purchases, except wind power purchases which are excluded in accordance with the 43393 Order. In addition to the wind purchases, swap transactions and MISO virtual transactions for generation and load are not subject to the Purchased Power Daily Benchmark. NIPSCO did not have any swap or virtual transactions during this FAC period.

Q45. Is NIPSCO seeking to recover any MWhs of purchased power during this reconciliation period that are in excess of the Purchased Power Daily Benchmarks calculated pursuant to the 43526 Order?

A45. Yes. In October 2011, 1,638.87 MWhs of purchased power were in excess of the Purchased Power Daily Benchmarks. In November 2011, 535.55 MWhs of purchased power were in excess of the Purchased Power Daily Benchmarks. In December 2011, 722.56 MWhs of purchased power were in excess of the Purchased Power Daily Benchmarks.

Q46. Have any purchases over the Purchased Power Benchmark during the reconciliation period been determined to be non-recoverable?

A46. No. In accordance with the procedures outlined in the 43526 Order, the Purchases over the Purchased Power Benchmark that supply jurisdictional load that offset available NIPSCO resources that were not dispatched by MISO or are otherwise eligible under the procedures outlined in the 43526 Order are therefore recoverable.

Q47. Please describe the RSG Benchmark approved in the 43665 Order.

A47. In the 43665 Order, the Commission found that each day, a "Benchmark" is established based upon a generic GT, using a generic GT heat rate of 12,500 Btu/kWh using the day ahead natural gas prices for the NYMEX Henry Hub, plus a $.60/MBtu gas transport charge for a generic gas-fired GT ("RSG Daily Benchmark"). Day-Ahead RSG Distribution Amounts

("DA RSG") as reported on NIPSCO's S-14 settlement statements are recovered as fuel costs in the FAC. Real-Time RSG First Pass Distribution Amounts ("RT RSG") as reported on NIPSCO's S-14 settlement statements at an hourly $/MWh rate are added to the Real-Time Marginal Energy Component ("MEC") of the Locational Marginal Price ("LMP") in each hour to compute an Hourly RSG Reference Point. This reference point is compared to the RSG Daily Benchmark. During those hours when the RSG Reference Point is at or below the RSG Daily Benchmark, the RT RSG charges incurred during those hours are recovered in the FAC. NIPSCO is not seeking recovery of any RT RSG charges above the RSG Daily Benchmark at this time. The RSG Benchmarks for this reconciliation period are set forth in Petitioner's Exhibit No. 3-B.

Q48. Have there been any Commission orders issued since the last quarterly filing that impact NIPSCO's FAC proceedings?

A48. Yes, on December 21, 2011 the Commission issued an Order in Cause No. 43969, NIPSCO's electric rate case ("43969 Order").

Q49. Did the 43969 Order require any changes in NIPSCO's business practices?

A49. Yes. The 43969 Order approved the Rider 675 – Interruptible Industrial Service, which provides for credits to be paid to certain industrial customers that agree to interrupt their service if certain criteria are met.

Q50. During the reconciliation period, did NIPSCO interrupt any of these industrial customers?

A50. No. Rider 675 was only in place from December 27 through December 31, 2011, and during that period, no interruptions were called.

Q51. Does this conclude your prepared direct testimony?

A51. Yes.

VERIFICATION

I, Daniel T. Williamson, Executive Director of Energy Supply and Trading for Northern Indiana Public Service Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Daniel T. Williamson

Daniel T. Williamson

Dated: February 1, 2012

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Daily Purchase Power Benchmark Calculation
Cause No. 43526, Approved August 25, 2010
OCTOBER, 2011

Line No.	Date	Heat Rate Btu/KWh	Fuel Cost * $/MMBtu	Transportation $/MMBtu	Fuel + Trans $/MMBtu	Benchmark $/MWh	Line No.
1	10/1/2011	12,500	3.730	0.17	3.900	48.75	1
2	10/2/2011	12,500	3.730	0.17	3.900	48.75	2
3	10/3/2011	12,500	3.730	0.17	3.900	48.75	3
4	10/4/2011	12,500	3.585	0.17	3.755	46.94	4
5	10/5/2011	12,500	3.605	0.17	3.775	47.19	5
6	10/6/2011	12,500	3.645	0.17	3.815	47.69	6
7	10/7/2011	12,500	3.445	0.17	3.615	45.19	7
8	10/8/2011	12,500	3.310	0.17	3.480	43.50	8
9	10/9/2011	12,500	3.310	0.17	3.480	43.50	9
10	10/10/2011	12,500	3.310	0.17	3.480	43.50	10
11	10/11/2011	12,500	3.370	0.17	3.540	44.25	11
12	10/12/2011	12,500	3.505	0.17	3.675	45.94	12
13	10/13/2011	12,500	3.550	0.17	3.720	46.50	13
14	10/14/2011	12,500	3.450	0.17	3.620	45.25	14
15	10/15/2011	12,500	3.520	0.17	3.690	46.13	15
16	10/16/2011	12,500	3.520	0.17	3.690	46.13	16
17	10/17/2011	12,500	3.520	0.17	3.690	46.13	17
18	10/18/2011	12,500	3.810	0.17	3.980	49.75	18
19	10/19/2011	12,500	3.765	0.17	3.935	49.19	19
20	10/20/2011	12,500	3.825	0.17	3.995	49.94	20
21	10/21/2011	12,500	3.840	0.17	4.010	50.13	21
22	10/22/2011	12,500	3.725	0.17	3.895	48.69	22
23	10/23/2011	12,500	3.725	0.17	3.895	48.69	23
24	10/24/2011	12,500	3.725	0.17	3.895	48.69	24
25	10/25/2011	12,500	3.790	0.17	3.960	49.50	25
26	10/26/2011	12,500	3.885	0.17	4.055	50.69	26
27	10/27/2011	12,500	4.000	0.17	4.170	52.13	27
28	10/28/2011	12,500	3.925	0.17	4.095	51.19	28
29	10/29/2011	12,500	3.865	0.17	4.035	50.44	29
30	10/30/2011	12,500	3.865	0.17	4.035	50.44	30
31	10/31/2011	12,500	3.865	0.17	4.035	50.44	31

* Platt's Gas Daily Midpoint price for Chicago City Gate

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Daily Purchase Power Benchmark Calculation
Cause No. 43526, Approved August 25, 2010
NOVEMBER, 2011

Line No.	Date	Heat Rate Btu/KWh	Fuel Cost * $/MMBtu	Transportation $/MMBtu	Fuel + Trans $/MMBtu	Benchmark $/MWh	Line No.
1	11/1/2011	12,500	3.795	0.17	3.965	49.56	1
2	11/2/2011	12,500	3.600	0.17	3.770	47.13	2
3	11/3/2011	12,500	3.635	0.17	3.805	47.56	3
4	11/4/2011	12,500	3.675	0.17	3.845	48.06	4
5	11/5/2011	12,500	3.655	0.17	3.825	47.81	5
6	11/6/2011	12,500	3.655	0.17	3.825	47.81	6
7	11/7/2011	12,500	3.655	0.17	3.825	47.81	7
8	11/8/2011	12,500	3.540	0.17	3.710	46.38	8
9	11/9/2011	12,500	3.720	0.17	3.890	48.63	9
10	11/10/2011	12,500	3.820	0.17	3.990	49.88	10
11	11/11/2011	12,500	3.690	0.17	3.860	48.25	11
12	11/12/2011	12,500	3.420	0.17	3.590	44.88	12
13	11/13/2011	12,500	3.420	0.17	3.590	44.88	13
14	11/14/2011	12,500	3.420	0.17	3.590	44.88	14
15	11/15/2011	12,500	3.325	0.17	3.495	43.69	15
16	11/16/2011	12,500	3.365	0.17	3.535	44.19	16
17	11/17/2011	12,500	3.405	0.17	3.575	44.69	17
18	11/18/2011	12,500	3.390	0.17	3.560	44.50	18
19	11/19/2011	12,500	3.295	0.17	3.465	43.31	19
20	11/20/2011	12,500	3.295	0.17	3.465	43.31	20
21	11/21/2011	12,500	3.295	0.17	3.465	43.31	21
22	11/22/2011	12,500	3.290	0.17	3.460	43.25	22
23	11/23/2011	12,500	3.345	0.17	3.515	43.94	23
24	11/24/2011	12,500	3.010	0.17	3.180	39.75	24
25	11/25/2011	12,500	3.010	0.17	3.180	39.75	25
26	11/26/2011	12,500	3.010	0.17	3.180	39.75	26
27	11/27/2011	12,500	3.010	0.17	3.180	39.75	27
28	11/28/2011	12,500	3.010	0.17	3.180	39.75	28
29	11/29/2011	12,500	3.415	0.17	3.585	44.81	29
30	11/30/2011	12,500	3.660	0.17	3.830	47.88	30

* Platt's Gas Daily Midpoint price for Chicago City Gate

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Daily Purchase Power Benchmark Calculation
Cause No. 43526, Approved August 25, 2010
DECEMBER, 2011

Line No.	Date	Heat Rate Btu/KWh	Fuel Cost * $/MMBtu	Transportation $/MMBtu	Fuel + Trans $/MMBtu	Benchmark $/MWh	Line No.
1	12/1/2011	12,500	3.670	0.17	3.840	48.00	1
2	12/2/2011	12,500	3.575	0.17	3.745	46.81	2
3	12/3/2011	12,500	3.510	0.17	3.680	46.00	3
4	12/4/2011	12,500	3.510	0.17	3.680	46.00	4
5	12/5/2011	12,500	3.510	0.17	3.680	46.00	5
6	12/6/2011	12,500	3.675	0.17	3.845	48.06	6
7	12/7/2011	12,500	3.615	0.17	3.785	47.31	7
8	12/8/2011	12,500	3.605	0.17	3.775	47.19	8
9	12/9/2011	12,500	3.610	0.17	3.780	47.25	9
10	12/10/2011	12,500	3.425	0.17	3.595	44.94	10
11	12/11/2011	12,500	3.425	0.17	3.595	44.94	11
12	12/12/2011	12,500	3.425	0.17	3.595	44.94	12
13	12/13/2011	12,500	3.205	0.17	3.375	42.19	13
14	12/14/2011	12,500	3.225	0.17	3.395	42.44	14
15	12/15/2011	12,500	3.215	0.17	3.385	42.31	15
16	12/16/2011	12,500	3.180	0.17	3.350	41.88	16
17	12/17/2011	12,500	3.120	0.17	3.290	41.13	17
18	12/18/2011	12,500	3.120	0.17	3.290	41.13	18
19	12/19/2011	12,500	3.120	0.17	3.290	41.13	19
20	12/20/2011	12,500	3.160	0.17	3.330	41.63	20
21	12/21/2011	12,500	3.230	0.17	3.400	42.50	21
22	12/22/2011	12,500	3.170	0.17	3.340	41.75	22
23	12/23/2011	12,500	3.180	0.17	3.350	41.88	23
24	12/24/2011	12,500	2.995	0.17	3.165	39.56	24
25	12/25/2011	12,500	2.995	0.17	3.165	39.56	25
26	12/26/2011	12,500	2.995	0.17	3.165	39.56	26
27	12/27/2011	12,500	2.995	0.17	3.165	39.56	27
28	12/28/2011	12,500	3.185	0.17	3.355	41.94	28
29	12/29/2011	12,500	3.165	0.17	3.335	41.69	29
30	12/30/2011	12,500	3.105	0.17	3.275	40.94	30
31	12/31/2011	12,500	3.105	0.17	3.275	40.94	31

* Platt's Gas Daily Midpoint price for Chicago City Gate

NORTHERN INDIANA PUBLIC SERVICE COMPANY
Revenue Sufficiency Guarantee Benchmark Calculation
Cause No. 43665, Approved June 30, 2009
OCTOBER, 2011

Line No.	Date	NG at Henry Hub $/mmbtu	NG Transportation $/mmbtu	GT Heat Rate btu/kwh	RSG Benchmark $/mwh	Line No.
1	10/1/2011	3.680	0.60	12,500	53.50	1
2	10/2/2011	3.680	0.60	12,500	53.50	2
3	10/3/2011	3.680	0.60	12,500	53.50	3
4	10/4/2011	3.565	0.60	12,500	52.06	4
5	10/5/2011	3.560	0.60	12,500	52.00	5
6	10/6/2011	3.625	0.60	12,500	52.81	6
7	10/7/2011	3.490	0.60	12,500	51.13	7
8	10/8/2011	3.400	0.60	12,500	50.00	8
9	10/9/2011	3.400	0.60	12,500	50.00	9
10	10/10/2011	3.400	0.60	12,500	50.00	10
11	10/11/2011	3.415	0.60	12,500	50.19	11
12	10/12/2011	3.520	0.60	12,500	51.50	12
13	10/13/2011	3.540	0.60	12,500	51.75	13
14	10/14/2011	3.425	0.60	12,500	50.31	14
15	10/15/2011	3.490	0.60	12,500	51.13	15
16	10/16/2011	3.490	0.60	12,500	51.13	16
17	10/17/2011	3.490	0.60	12,500	51.13	17
18	10/18/2011	3.720	0.60	12,500	54.00	18
19	10/19/2011	3.630	0.60	12,500	52.88	19
20	10/20/2011	3.585	0.60	12,500	52.31	20
21	10/21/2011	3.605	0.60	12,500	52.56	21
22	10/22/2011	3.545	0.60	12,500	51.81	22
23	10/23/2011	3.545	0.60	12,500	51.81	23
24	10/24/2011	3.545	0.60	12,500	51.81	24
25	10/25/2011	3.605	0.60	12,500	52.56	25
26	10/26/2011	3.620	0.60	12,500	52.75	26
27	10/27/2011	3.645	0.60	12,500	53.06	27
28	10/28/2011	3.590	0.60	12,500	52.38	28
29	10/29/2011	3.630	0.60	12,500	52.88	29
30	10/30/2011	3.630	0.60	12,500	52.88	30
31	10/31/2011	3.630	0.60	12,500	52.88	31

Sources:
For NG: MySource, Market Prices community, Gas Daily Prices, location Henry Hub,
Mid Point Price for Flow Date (not Transaction Date).
The same information can also be seen in Platts Gas Daily publication (this is a physical price and not a financial price)

Calculations:
Benchmark = ($/mmbtu + $0.60/mmbtu) * 12,500 btu/kwh * 1,000 kwh/mwh * mmbtu/1,000,000 btu

Symbols:
NG = Natural Gas GT = Gas Turbine RSG = Revenue Sufficiency Guarantee

* No market price published, used average of the day before and after

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Revenue Sufficiency Guarantee Benchmark Calculation
Cause No. 43665, Approved June 30, 2009
NOVEMBER 2011

Line No.	Date	NG at Henry Hub $/mmbtu	NG Transportation $/mmbtu	GT Heat Rate btu/kwh	RSG Benchmark $/mwh	Line No.
1	11/1/2011	3.670	0.60	12,500	53.38	1
2	11/2/2011	3.495	0.60	12,500	51.19	2
3	11/3/2011	3.390	0.60	12,500	49.88	3
4	11/4/2011	3.385	0.60	12,500	49.81	4
5	11/5/2011	3.455	0.60	12,500	50.69	5
6	11/6/2011	3.455	0.60	12,500	50.69	6
7	11/7/2011	3.455	0.60	12,500	50.69	7
8	11/8/2011	3.345	0.60	12,500	49.31	8
9	11/9/2011	3.420	0.60	12,500	50.25	9
10	11/10/2011	3.560	0.60	12,500	52.00	10
11	11/11/2011	3.485	0.60	12,500	51.06	11
12	11/12/2011	3.295	0.60	12,500	48.69	12
13	11/13/2011	3.295	0.60	12,500	48.69	13
14	11/14/2011	3.295	0.60	12,500	48.69	14
15	11/15/2011	3.170	0.60	12,500	47.13	15
16	11/16/2011	3.125	0.60	12,500	46.56	16
17	11/17/2011	3.115	0.60	12,500	46.44	17
18	11/18/2011	3.120	0.60	12,500	46.50	18
19	11/19/2011	3.015	0.60	12,500	45.19	19
20	11/20/2011	3.015	0.60	12,500	45.19	20
21	11/21/2011	3.015	0.60	12,500	45.19	21
22	11/22/2011	2.935	0.60	12,500	44.19	22
23	11/23/2011	3.055	0.60	12,500	45.69	23
24	11/24/2011	2.795	0.60	12,500	42.44	24
25	11/25/2011	2.795	0.60	12,500	42.44	25
26	11/26/2011	2.795	0.60	12,500	42.44	26
27	11/27/2011	2.795	0.60	12,500	42.44	27
28	11/28/2011	2.795	0.60	12,500	42.44	28
29	11/29/2011	3.070	0.60	12,500	45.88	29
30	11/30/2011	3.385	0.60	12,500	49.81	30
31						31

Sources:
For NG: MySource, Market Prices community, Gas Daily Prices, location Henry Hub,
Mid Point Price for Flow Date (not Transaction Date).
The same information can also be seen in Platts Gas Daily publication (this is a physical price and not a financial price)

Calculations:
Benchmark = ($/mmbtu + $0.60/mmbtu) * 12,500 btu/kwh * 1,000 kwh/mwh * mmbtu/1,000,000 btu

Symbols:
NG = Natural Gas GT = Gas Turbine RSG = Revenue Sufficiency Guarantee

* No market price published, used average of the day before and after

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Revenue Sufficiency Guarantee Benchmark Calculation
Cause No. 43665, Approved June 30, 2009
DECEMBER, 2011

Line No.	Date	NG at Henry Hub $/mmbtu	NG Transportation $/mmbtu	GT Heat Rate btu/kwh	RSG Benchmark $/mwh	Line No.
1	12/1/2011	3.530	0.60	12,500	51.63	1
2	12/2/2011	3.480	0.60	12,500	51.00	2
3	12/3/2011	3.350	0.60	12,500	49.38	3
4	12/4/2011	3.350	0.60	12,500	49.38	4
5	12/5/2011	3.350	0.60	12,500	49.38	5
6	12/6/2011	3.375	0.60	12,500	49.69	6
7	12/7/2011	3.425	0.60	12,500	50.31	7
8	12/8/2011	3.445	0.60	12,500	50.56	8
9	12/9/2011	3.420	0.60	12,500	50.25	9
10	12/10/2011	3.295	0.60	12,500	48.69	10
11	12/11/2011	3.295	0.60	12,500	48.69	11
12	12/12/2011	3.295	0.60	12,500	48.69	12
13	12/13/2011	3.130	0.60	12,500	46.63	13
14	12/14/2011	3.115	0.60	12,500	46.44	14
15	12/15/2011	3.085	0.60	12,500	46.06	15
16	12/16/2011	3.055	0.60	12,500	45.69	16
17	12/17/2011	3.015	0.60	12,500	45.19	17
18	12/18/2011	3.015	0.60	12,500	45.19	18
19	12/19/2011	3.015	0.60	12,500	45.19	19
20	12/20/2011	3.020	0.60	12,500	45.25	20
21	12/21/2011	3.060	0.60	12,500	45.75	21
22	12/22/2011	3.050	0.60	12,500	45.63	22
23	12/23/2011	3.085	0.60	12,500	46.06	23
24	12/24/2011	2.975	0.60	12,500	44.69	24
25	12/25/2011	2.975	0.60	12,500	44.69	25
26	12/26/2011	2.975	0.60	12,500	44.69	26
27	12/27/2011	2.975	0.60	12,500	44.69	27
28	12/28/2011	3.085	0.60	12,500	46.06	28
29	12/29/2011	3.075	0.60	12,500	45.94	29
30	12/30/2011	3.025	0.60	12,500	45.31	30
31	12/31/2011	3.025	0.60	12,500	45.31	31

Sources:
For NG: MySource, Market Prices community, Gas Daily Prices, location Henry Hub,
Mid Point Price for Flow Date (not Transaction Date).
The same information can also be seen in Platts Gas Daily publication (this is a physical price and not a financial price)

Calculations:
Benchmark = ($/mmbtu + $0.60/mmbtu) * 12,500 btu/kwh * 1,000 kwh/mwh * mmbtu/1,000,000 btu

Symbols:
NG = Natural Gas GT = Gas Turbine RSG = Revenue Sufficiency Guarantee

* No market price published, used average of the day before and after

VERIFIED DIRECT TESTIMONY OF KEVIN A. STRNATKA

Q1. Please state your name, business address and title.

A1. My name is Kevin A. Strnatka. My business address is 801 E. 86th Avenue, Merrillville, Indiana 46410. I am Director, Fuel Supply, for Northern Indiana Public Service Company ("NIPSCO" or "Company").

Q2. Please describe your educational and employment background.

A2. I graduated from St. Joseph's College with a Bachelor of Science degree in Business Management/Economics and began work for NIPSCO in 1974. I have served in various positions with NIPSCO. In 1990, I was promoted to the position of Manager, Material Purchasing. In 1993, I was promoted to the position of Manager, Fuel Supply. In 1994, I was promoted to the position of Manager, Production Operations Planning. In 1997, I assumed the responsibilities of the Fuel Supply Department, and in 1998, I was promoted to my current position, Director, Fuel Supply.

Q3. What are your responsibilities as Director, Fuel Supply?

A3. As Director, Fuel Supply, I am responsible for supervising the purchase and transport of coal to be used for generating electric energy, including administration of the fuel contracts and the pricing provisions of these contracts.

Q4. Are you familiar with the Company's Verified Petition, including the exhibits attached thereto, initiating this proceeding, a copy of which has been marked <u>Petitioner's Exhibit No. 1-A</u>?

A4. Yes.

Q5. What is the purpose of your testimony in this proceeding?

A5. The purpose of my testimony is to (1) describe NIPSCO's coal procurement process; (2) provide the prices NIPSCO paid for coal in the reconciliation period and explain the factors that affected those prices; and (3) provide NIPSCO's estimated coal prices for the forecast period and explain the factors that support NIPSCO's forecast.

Q6. What fuels are used to power NIPSCO's generating units?

A6. For the three months ended December 31, 2011, NIPSCO's fuel requirements for its generating units were supplied by coal (83.36%) and the remainder by natural gas (16.64%), including Sugar Creek Generating Station. NIPSCO uses a blend of Powder River Basin ("PRB") coal and Pittsburgh #8 ("Pitt8") coal in Unit 12 at its Michigan City Generating

Station, Illinois Basin high sulfur ("ILB") coal in Units 7 and 8 at its Bailly Generating Station, a blend of PRB coal and Pitt8 coal in Unit 14, and PRB coal in Unit 15 and ILB coal in Units 17 and 18 at its R. M. Schahfer Generating Station.

Q7. Since the great bulk of NIPSCO's electric generating capacity is fired by coal, what factors must be considered in purchasing coal for those generating units?

A7. Factors that are considered in purchasing coal include the delivered price, the coal quality that is best suited for a particular generating unit, the sulfur content, and the economic and technical suitability of certain low cost fuels to be blended at the generating units to maintain the lowest, reasonably possible "as-burned" fuel cost. The availability, reliability and diversity of particular coal suppliers and coal transporters are also considered in NIPSCO's fuel procurement practices.

Q8. How does NIPSCO purchase its coal supplies?

A8. Effective January 1, 2012, NIPSCO has four (4) long term contracts with three (3) coal producers. These coal producers are Arch Coal Sales Company (PRB coal), Consol Pennsylvania Coal Company (Pitt8 coal) and two (2) ILB coal contracts with Peabody COALSALES, LLC. NIPSCO is currently negotiating term contracts with two (2) additional PRB coal suppliers that would be effective around April 1, 2012. If needed, the remainder of NIPSCO's coal requirements would be met through spot purchases.

Q9. Did NIPSCO make any spot purchases during the reconciliation period from October 2011 to December 2011?

A9. Yes. NIPSCO made one (1) spot purchase of ILB coal for Units 7 and 8 at its Bailly Generating Station and for Units 17 and 18 at its R.M. Schahfer Generating Station.

Q10. Please describe the process NIPSCO utilizes to procure its long term coal contracts.

A10. NIPSCO competitively bids all coal purchased under a long term agreement. A Request for Proposal ("RFP") is prepared and sent to previously approved bidders who can supply the type of coal required. Bidders' proposals are returned to the Corporate Auditor and a formal bid opening is held with Auditing and Fuel Supply representatives present. NIPSCO prepares a preliminary evaluation sheet incorporating all of the bidder information such as mine origin, Btu, sulfur, ash, available tons per year and price on both a per ton and $ per million Btu basis. NIPSCO creates a final evaluation sheet that ranks bidders on a delivered cost basis. The final evaluation sheet for each of the bidders includes coal cost, transportation cost and any adjustments required to place all bids on an equivalent basis. NIPSCO then negotiates price and commercial terms and conditions with the low evaluated bidder(s). The successful bidder(s) executes a term contract with NIPSCO after legal and executive approval.

Q11. Does NIPSCO have a financial interest in any of the coal producers currently under contract?

A11. No.

Q12. Do all of NIPSCO's long term coal contracts allow for price adjustments?

A12. Two (2) of NIPSCO's long term contracts have firm prices that increase each year as specified in the contract. One (1) long term contract has prices that are adjusted annually for the succeeding year based on the average weekly indexed prices of that particular coal in the previous year. One (1) long term contract has an annual market price reopener that will determine the contract coal price for the succeeding year of the contract. All term coal contracts are price adjusted (up or down) on a Btu per pound basis. In addition to the Btu adjustments, PRB coal term contracts are adjusted (up or down) based on sulfur content.

Q13. What is the purpose for price adjustments in long term coal contracts?

A13. With the volatility in the coal markets, producers and customers are reluctant to execute fixed price long term contracts without some type of market price adjustment mechanism. Maintaining a market price balance is beneficial to both parties. NIPSCO's coal contracts are usually for a term of no more than three (3) to five (5) years, and typically the price is adjusted each contract year.

Q14. How does NIPSCO decide whether to pay a requested price increase based on contract provisions?

A14. NIPSCO's Fuel Supply Department, which is responsible for administering all coal contracts, verifies that only contract allowable changes are made to the mine and transportation prices. After a price adjustment is received, NIPSCO requests supporting evidence in the form of actual invoices and records, as well as published government data, to justify the price adjustment. No price adjustments are made until NIPSCO is satisfied that the charges are in accordance with the contract, and are justified by actual costs or changes in cost indices.

Q15. What was the delivered cost of coal for NIPSCO for the twelve months ending December 31, 2011 and for the reconciliation period of October, November and December 2011?

A15. The delivered cost of coal for the twelve months ending December 31, 2011 was $51.43 per ton or $2.570 per million Btu. The delivered cost of coal for the period of October, November and December 2011 was $49.74 per ton or $2.522 per million Btu.

Q16. What was the average spot market price of coal during the reconciliation period?

A16. The average spot market price of coal during the reconciliation period was $13.75 per ton for PRB coal, $50.51 per ton for ILB coal and $75.90 per ton for Pitt8 coal. NIPSCO tracks spot market pricing by reviewing coal publications from Argus, Platts and Energy Publishing. These average spot market prices do not include transportation charges.

Q17. What market factors do you believe affected the supply, demand, and

cost of coal during the reconciliation period?

A17. Coal supply during the reconciliation period was impacted largely by the weather, the continuing decrease in the price of natural gas and the softening of the export markets. The mild weather has decreased electricity demand and placed coal units in economic reserve, causing inventories to move higher. The continuing fall of natural gas prices is causing additional coal to gas switching, thereby creating more coal supply availability on the market. Finally, due to the European debt crisis and the slowing down of the Asian coal markets, it appears less domestic coal is being exported overseas. Consequently, due to the oversupply of coal on the markets, NIPSCO's coal costs during the reconciliation period reflected a slight decrease in price.

Q18. What factors do you believe affected NIPSCO's delivered cost of coal during the reconciliation period?

A18. NIPSCO's delivered cost of coal during the reconciliation period decreased compared to the third quarter of 2011 from $51.76 per ton or $2.581 per million Btu to $49.74 per ton or $2.522 per million Btu. This reduction can be attributed to a decrease in price in a ILB contract coal, , taking less high cost Pitt8 coal and slightly lower fuel surcharges.

Q19. What is NIPSCO's estimated delivered cost of coal during the forecast period of April 2012 through June 2012?

A19. NIPSCO anticipates that its delivered cost of coal for the forecast period of April 2012 through June 2012 will be approximately $51.43 per ton or an estimated $2.58 per million Btu. A PRB coal solicitation was issued on October 11, 2011, to replace contract coal commencing around April 1, 2012. Currently, NIPSCO is negotiating with suppliers for a multi-year term for high demand, ultra-low-sulfur PRB coal. Potential increases in price for this type of coal were anticipated due to the implementation of the Cross-State Air Pollution Rule ("CSAPR") which was scheduled to become effective on January 1, 2012. However, on December 30, 2011 the United States Court of Appeals for the District of Columbia issued an order staying this rule. As a result, CSAPR did not go into effect on January 1, 2012 and there is some uncertainty regarding the rule. Also, NIPSCO has negotiated with one producer a substantial price reduction for ILB contract coal for 2012. Additionally, NIPSCO has negotiated a new multi-year transportation agreement for deliveries of both PRB and high-sulfur coal. Transportation rates for deliveries of PRB coal and part of NIPSCO's high-sulfur coal requirements will be slightly less than current rates in 2011. Overall, NIPSCO is currently projecting a delivered coal cost of $2.58 per million Btu for the forecast period. It is important to note that the projected delivered cost of $2.58 per million Btu in the forecast period could be influenced by the economic dispatch of our coal units and the volatility in the diesel fuel market.

Q20. How does this compare to the average spot market prices for the 2012 calendar year?

A20. The average spot market prices for calendar year 2012 are currently $14.22 per ton for PRB coal, $48.71 per ton for ILB coal and $76.44 per ton for Pitt8 coal. These average spot market prices do not include the cost of transportation.

Q21. What information does NIPSCO use to develop the estimate for the forecast period?

A21. In developing the estimate for the forecast period, NIPSCO incorporates all current coal contract prices, estimates of any coal contract price adjustments that might be warranted, transportation contract prices, an assessment of the pricing impact of fuel surcharges on the delivered cost based on current price of crude oil, and an evaluation of the spot market price of coal. These inputs are provided to NIPSCO's Generation Dispatch & Marketing Group to be used in quarterly updates of PROMOD to develop costs based on demand and projected load forecasts.

Q22. Please describe the factors NIPSCO believes will impact the supply, demand, and cost of coal during the forecast period?

A22. The factors that NIPSCO believes will impact the supply, demand and cost of coal during the forecast period include the continuing precipitous drop in pricing of natural gas because of a sharp increase in unconventional supply, which is creating more coal to gas switching in the power sector, continued mild weather furthering decreases in electrical demand, softening international demand for domestic coal, uncertainty regarding the duration of the CSAPR stay and regarding the outcome of the legal challenge to the CSAPR rule, and possible economic improvement. Overall, NIPSCO is expecting relatively flat coal pricing during the forecast period.

Q23. Please describe the factors NIPSCO believes will impact the delivered cost of coal during the forecast period.

A23. Currently, NIPSCO believes the delivered cost of coal for the forecast period will be relatively flat. The cost of crude has been presently ranging between $97 and $102 per barrel. If the price of crude remains within this range NIPSCO's delivered coal cost will be minimally influenced by fuel surcharges paid to the railroads.

Q24. Has NIPSCO made every reasonable effort to acquire fuel so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible?

A24. Yes.

Q25. Please discuss the recommendation regarding coal transportation hedging that was first raised in FAC91.

A25. In FAC91, the Industrial Group recommended that NIPSCO should develop and implement a hedging policy as soon as possible and plan for the portion of its coal transportation costs that are subject to automatic adjustment based on on-highway diesel fuel price indices or other petroleum price indices. NIPSCO indicated that it would review the

Industrial Group's recommendation regarding coal transportation hedging to analyze, among other things, the possible benefits and costs of such a hedging policy, the various tools available to accomplish a hedging program, and the reduction in transportation price volatility that could be achieved through a hedging policy. Since my testimony in FAC93, NIPSCO has been working to determine the amount of transportation cost that is exposed to risk of automatic adjustment and against what commodities the risk is exposed. This is complicated by the fact that the transportation contracts include fuel surcharge triggers against two different commodities. One contract uses WTI crude prices as its trigger while another uses Highway Diesel fuel. In addition, different contracts have separate fuel surcharge escalators once a trigger price is reached. Notwithstanding the above challenges, two of the three contracts that create fuel surcharge exposure will expire at the end of 2012. This may provide an opportunity to mitigate one of the most onerous fuel surcharge mechanisms associated with a railroad that delivers all coal to NIPSCO's R.M. Schahfer Generating Station. These contract negotiations will commence later this year. NIPSCO's recommendation would be to defer a decision regarding a coal transportation hedging program until both new transportation agreements have been negotiated, particularly the fuel surcharge mechanism associated with coal delivered to the R.M. Schahfer Generating Station. NIPSCO will continue to reach out and be available to work informally with stakeholders to review further analysis after new agreements take effect. If warranted, the next step would then be to review different options for implementing a hedging program.

Q26. Does this complete your prepared direct testimony?

A26. Yes.

VERIFICATION

I, Kevin A. Strnatka, Director, Fuel Supply for Northern Indiana Public Service Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Kevin A. Strnatka

Dated: February 1, 2012

VERIFIED DIRECT TESTIMONY OF MITCHELL F. HERSHBERGER

Q1. Please state your name, title and business address.

A1. My name is Mitchell E. Hershberger. My title is Manager Business & Support Services for the Generation Department of Northern Indiana Public Service Company ("NIPSCO" or the "Company"). My business address is 2755 Raystone Drive, Valparaiso, Indiana 46383.

Q2. Please describe your educational and employment background.

A2. I am a graduate of Indiana University and hold Bachelor of Science and Master of Business Administration degrees. I have been employed by NiSource Inc. or NIPSCO since March of 1987 in a variety of accounting and finance positions.

Q3. What are you responsibilities as Manager Business & Support Services?

A3. My current responsibilities include budgeting, cost control and administrative services for the NIPSCO Generation Department.

Q4. Are you familiar with the Company's Verified Petition, including the exhibits attached thereto, initiating this proceeding, a copy of which has been marked <u>Petitioner's Exhibit No. 1-A</u>?

A4. Yes.

Q5. What is the purpose of your direct testimony in this proceeding?

A5. The purpose of my testimony is to provide information relevant to Paragraph 6 of Exhibit A - Settlement Terms, attached to the Stipulation and Agreement filed October 16, 2007 in Cause No. 38706-FAC71-S1 approved by the Commission on January 30, 2008 ("FAC71-S1 Agreement") and Paragraph 6(f.) of the Stipulation and Agreement filed September 23, 2009 in Cause No. 38706-FAC80-S1 approved by the Commission on November 4, 2009 ("FAC80-S1 Agreement") (collectively, the "Reporting Agreements"). Paragraph 6 of the FAC71-S1 Agreement calls for NIPSCO to submit testimony in its quarterly FAC proceedings regarding major forced outages that occur within the pertinent FAC timeframe. Under this provision, NIPSCO must describe the length of the major forced outage, the cause, the generating unit involved and proposed solutions to prevent such outages from occurring in the future. In addition to the above provision regarding the details of each major forced outage, Paragraph 6(f.) of the FAC80-S1 Agreement calls for NIPSCO to file testimony describing the details of and the steps taken to minimize such major forced outages in the future. Paragraph 6(f.) of the FAC80-S1 Agreement defines a "major forced outage" as a unit forced outage lasting longer than three consecutive days.

Q6. What exhibits are you sponsoring?

A6. I am sponsoring Petitioner's Exhibit No. 5-A, which was prepared by me or under my direction and supervision.

Q7. Please address how NIPSCO has complied with the requirements of the Reporting Agreements.

A7. To summarize the information required, NIPSCO prepared a chart that lists the units that experienced forced outages, the start date of the forced outage and the period of time that the outage lasted. It also includes the detailed reasons for the forced outage and the short term and, if appropriate, long term remedies that NIPSCO has or will implement in order to prevent such outages from occurring in the future. The chart is attached to my testimony as Petitioner's Exhibit No. 5-A.

Q8. Please describe Petitioner's Exhibit No. 5-A.

A8. Petitioner's Exhibit No. 5-A presents a description and summary of each major forced outage. In addition, Petitioner's Exhibit No. 5-A addresses major forced outages during the fourth quarter of 2011, which is the reconciliation period in this FAC proceeding. While NIPSCO considers Petitioner's Exhibit No. 5-A to be a reasonable presentation of the requirements of the Reporting Agreements, NIPSCO will supplement or restate this information in a manner the parties or the Commission deem necessary.

Q9. Please summarize the forced outages during this FAC timeframe.

A9. During the timeframe of this FAC, there were four forced outages that lasted longer than 72 hours. Three of these were on a coal unit and one was on a gas fired combustion turbine. The coal unit outages were caused by boiler tube leaks. The combustion turbine forced outages were caused by a variety of mechanical failures.

Q10. Does this conclude your direct testimony?

A10. Yes.

VERIFICATION

I, Mitchell E. Hershberger, Manager Business & Support Services in the Generation Department of Northern Indiana Public Service Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Mitchell E. Hershberger

Mitchell E. Hershberger

Dated: February 2, 2012

Major Forced Outages for 4th Quarter of 2011

Station	Unit	Start Month	Start Day	Start Year	Hours off During this Quarter	Reason/Detail for Forced Outage	Remedy - Short and Long Term
RMS	17	11	28	11	79	Wall tube leak on east wall, elevation 5. Result of fireside corrosion.	**Short Term -** 1 dutchman and 3 pad welds **Long Term -** added to unit outage scope beginning Feb. 2012
RMS	17	12	4	11	85	Wall tube leak on east wall elevation 5 1/2, same tube as previous failure. Result of overheating.	**Short Term -** 1 dutchman. Thermal imaging of tube during boiler fill and a boroscope of the entire length of tube revealed no issues. **Long Term -** added to unit outage scope beginning Feb. 2012
RMS	17	12	7	11	78	Wall tube leak on east wall, lower slope adjacent to north dead air space. Failure due to fatigue.	**Short Term -**1 dutchman. Boiler hydro revealed no additional leaks. **Long Term -** added to unit outage scope beginning Feb. 2012
DHM	9					Fuel gas servo operated valve fails the "Home Sequence" test. The test involves fuel control scheme rapidly driving the fuel valve open then closed and checking the valve closed (home) limit switch to determine if the test succeeded. The Sentinell II, servo valve controller, would consistently lose the "Drive Ready" indication due to the servo drive controller not being able to drive the fuel gas servo operated valve to the closed (home) position. We are unable to troubleshoot logic from the Hawker-Sideley controller (turbine governor that develops the mass fuel flow signal) or the Sentinell II controller (turbine fuel servo valve controller that gets the signal from the Hawker-Sideley and sends it to the fuel gas servo operated valve) due to both development companies being out of service and having improper interface software to allow communication.	**Short Term -** Currently investigating if internal NIPSCO Engineering can replace the Hawker-Sideley and Sentinell II controllers with a controller/PLC that can be supported and interfaced. **Long Term -** Impliment plan to replace obsolete controllers with NIPSCO Engineering determined controller/PLC.
							Short Term - **Long Term -**
							Short Term - **Long Term -**

Notes:

1. When an event either began or ended outside of the requested time period, the Duration Hours reflect only the time that the unit was off during the October 1 thru December 31, 2011 time frame.
2. A Major Forced Outage is greater than 72 hours in duration during the current reporting period.

VERIFIED DIRECT TESTIMONY OF ROGER A. HUHN

Q1. Please state your name, business address and title.

A1. My name is Roger A. Huhn. My business address is 1500 165th Street, Hammond, Indiana 46320. I am the Manager – Strategic Initiatives in the Energy Supply and Trading Department for Northern Indiana Public Service Company ("NIPSCO" or "Company").

Q2. Please describe your educational and employment background.

A2. I graduated from Purdue University with an Associate Degree of Applied Science in Electrical Engineering Technology in May 1980 and a Bachelor of Science degree in Electrical Technology in May 1984. I graduated from Indiana University with a Master of Science in Business Administration in May 1988. I am also a North American Electric Reliability Corporation ("NERC") Certified System Operator. I began my employment with NIPSCO in 1980 in the District Engineering Department. I became an Electric System Supervisor at the Electric System Control Center in 1985. Since that time, I have held various engineering and planning positions in NIPSCO. In January 1996 I was promoted to Principal of Operations Support in Electric System Operations. In June 2001 I was promoted to Manager of Operations Support, Electric System Operations. Since 2001, I have held various managerial positions in the Energy Supply, Trading and Resource Planning areas. In January 2011, I assumed my current position of Manager – Strategic Initiatives in the Energy Supply and Trading Department.

Q3. What are your responsibilities as Manager – Strategic Initiatives in the Energy Supply and Trading Department?

A3. As Manager – Strategic Initiatives, I am responsible for ensuring that NIPSCO has the gas supply resources in place to meet forecasted gas and power system load demands. I am responsible for long-term and short-term gas supply resource planning, contract negotiations for interstate pipeline transportation and storage services. NIPSCO plans and analyzes gas supply, transport and storage resource needs and works with the Energy Supply group to meet those requirements.

Q4. Are you familiar with the Company's Verified Petition, including the exhibits attached thereto, initiating this proceeding, a copy of which has been marked <u>Petitioner's Exhibit No. 1-A</u>?

A4. Yes.

Q5. What is the purpose of your testimony in this proceeding?

A5. The purpose of my testimony is to address NIPSCO's gas purchasing practices for the purchase of natural gas when used as a fuel to serve the NIPSCO generation fleet.

Q6. Have there been any changes to NIPSCO's gas purchasing practices for NIPSCO's generation located on NIPSCO's gas distribution system during this period?

A6. No.

Q7. Have there been any changes to NIPSCO's gas purchasing practices for NIPSCO's generation located off of NIPSCO's gas distribution system (Sugar Creek Generating Station) during this period?

A7. No.

Q8. Has NIPSCO entered into any arrangements for natural gas under multiple year contracts?

A8. NIPSCO does not purchase natural gas under multiple year contracts to serve the NIPSCO generation fleet because natural gas is not used as a baseload fuel. Natural gas will normally be purchased on an intermittent basis when one of NIPSCO's gas-fired generation units is either economical to run or needs to run for operational purposes. Therefore, purchases are made on a spot basis rather than through a long-term arrangement.

Q9. Has NIPSCO made every reasonable effort to purchase natural gas so as to provide electricity to its customers at the lowest reasonable price?

A9. Yes.

Q10. Does this conclude your prepared direct testimony?

A10. Yes.

VERIFICATION

I, Roger A. Huhn, Manager – Strategic Initiatives in the Energy Supply and Trading Department for Northern Indiana Public Service Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Roger A. Huhn

Roger A. Huhn

Dated: February 2, 2012