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REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY	))	CAUSE NO. 43526

PREFILED TESTIMONY OF

MICHAEL J. MAJOROS, JR. – PUBLIC'S EXHIBIT NO. 7

ON BEHALF OF

THE INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

MAY 8, 2009

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TESTIMONY OF MICHAEL J. MAJOROS, JR.
CAUSE NO. 43526
NORTHERN INDIANA PUBLIC SERVICE COMPANY

Introduction

Q: Please state your name.

A: My name is Michael J. Majoros, Jr.

Q: By whom and in what capacity are you employed?

A: I am Vice President of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"), an economic consulting firm with offices at 1111 14th Street, N.W., Suite 300, Washington, D.C. 20005.

Q: Please describe Snavely King.

A: Snavely King is an economic consulting firm founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. Snavely King represents the interests of government agencies, businesses, and individuals who are consumers of telecom, public utility, and transportation services.

We have a professional staff of 12 economists, accountants, engineers and cost analysts. Most of our work involves the development, preparation and presentation of expert witness testimony before Federal and state regulatory agencies. Over the course of our 39-year history, members of the firm have participated in more than 1,000 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

1 **Q: Have you attached a summary of your qualifications and experience?**

2 A: Yes. My Appendix A contains a brief description of my qualifications and experience. My
3 Appendix B contains a listing of my appearances before state and Federal regulatory bodies.

4 **Q: At whose request are you appearing?**

5 A: I am appearing at the request of the Indiana Office of Utility Consumer Counselor
6 ("OUCC").

7 **Subject of Testimony**

8 **Q: What is the subject of your testimony?**

9 A: My testimony addresses matters relating to depreciation expense and depreciation studies.

10 **Q: Do you have any specific experience in the field of public utility depreciation?**

11 A: Yes. Among other areas, my firm specializes in the field of public utility depreciation. In
12 this regard, Snavely King's clients have ranged from consumer organizations such as
13 ratepayer advocates and regulatory commission staffs to large companies such as AT&T and
14 agencies such as the U.S. government.

15 We have appeared as expert witnesses on depreciation issues and matters before the
16 regulatory commissions of more than half of the states in the country. For example, I have
17 testified in well over 100 proceedings on the subject of public utility depreciation, and
18 represented various clients in several other proceedings in which depreciation was an issue
19 but was settled. I have also negotiated on behalf of clients in fifteen of the Federal
20 Communications Commission's ("FCC") Triennial Depreciation Represcription conferences.

21

Q: Have you ever testified before the Indiana Utility Regulatory Commission ("IURC")?

A: Yes, I have appeared before the IURC on several occasions. In fact, I testified in Cause No. 41746, which reaffirmed this Company's current depreciation rates.

Q: Have you ever appeared before the Federal Energy Regulatory Commission ("FERC")?

A: Yes, I presented testimony in two FERC proceedings: Docket Nos. RP79-12 and ER03-409 / ER03-666. I also prepared Comments submitted in Docket No. RM80-42 and Comments submitted by NASUCA in Docket No. RM02-7.

Purpose of Testimony

Q: What is the purpose of your testimony?

A: The OUCC asked me to review the depreciation-related testimony and exhibits of Northern Indiana Public Service Company ("NIPSCO" or "Company") witness Mr. John J. Spanos and other relevant witnesses for the Company. My testimony sets forth the results of my review and my independent depreciation study. The depreciation rates I am recommending result in a decrease to depreciation expense; by contrast, Mr. Spanos proposes an increase.

NIPSCO's Present Depreciation Rates

Q: Please identify the source of NIPSCO's present depreciation rates.

A: NIPSCO's present depreciation rates were established in a 1987 Order in Cause No. 38045, and reaffirmed in September 2002 in Cause No. 41746. On January 24, 2001, the Director of the Commission's Division of Accounting and Finance, filed a report ("First Staff Report"), based upon a review of [NIPSCO's] electric rates. At the same time, the Commission commenced an investigation, finding that it was "incumbent upon NIPSCO to demonstrate

why we should not revise and reduce its rates ..."[1] In that regard, NIPSCO filed a depreciation study conducted by Company witness Mr. Earl Robinson and in response, the OUCC filed my depreciation study. The Commission said:

> This is an investigation and not a rate case. The basic question is whether there is a need to depart from the 1987 Order, which fixed NIPSCO's current rates. A careful weighing of the evidence does not establish that a fair value set by us on NIPSCO's property in our 1987 Order, or return approved thereon, or the rates based thereon, were unjust, unreasonable, or otherwise in violation of the applicable statuary and case law.
>
> Continuation of the depreciation rates approved in the 1987 Order is also supported by the evidence in this case. NIPSCO and the OUCC presented extensive testimony on this issue, with NIPSCO supporting an increase in depreciation rates, which would have increased its depreciation expense by approximately $41.3 million annually (Resp. Rebuttal Ex. BAM-2, Schedule 1) and OUCC witness Majoros recommending depreciation rates that would have reduced depreciation expense by approximately $32.6 million. In their proposed orders, both the Industrials and the OUCC recommended that the depreciation rates as established by the 1987 Order be continued in force. That is exactly what is called for in the Settlement Agreement, and we find such resolution of this issue well supported by the evidence.[2]

Summary of NIPSCO's New Depreciation Requests

Q: Please summarize NIPSCO's new depreciation-related requests.

A: Mr. John Spanos conducted a study using electric and common plant balances as of December 31, 2007. Mr. Spanos' rates produce a $160,291,821 depreciation expense accrual

[1] September 23, 2002 Order Cause No. 41746, page 1.
[2] Id., page 16.

for electric and a $35,635,829 accrual for common, all based on December 31, 2007 plant.[3] These original figures did not include the depreciation expense related to the newly acquired Sugar Creek plant, which was incorporated into NIPSCO's rate base and revenue requirement in the Company's December 19, 2008 revised filing. The additional Sugar Creek depreciation expense, based on December 31, 2007 plant, is $5.8 million.[4]

Mr. Spanos' new depreciation rates collectively result in a $20.8 million increase to test year depreciation expense.[5] The Company is also requesting a 5-year amortization of $7.3 million of Sugar Creek depreciation expense deferred from December 1, 2008 through December 31, 2009 ($1,459,652 per year).[6]

Q: How did Mr. Spanos conduct his study?

A: Mr. Spanos used the retirement-rate method to study interim retirements and mass property lives.[7] He used both the equal life group ("ELG") procedure and the life span procedure to calculate average lives and remaining lives.[8] He used the straight-line method and remaining life technique to calculate depreciation rates.[9]

Mr. Spanos assumed 60-61 year life spans for steam production plants, 41-51 years for other production plants and operating licenses for the hydro plant lives.[10] Mr. Spanos

[3] Petitioner's Exhibit JJS-2, pp. 60 and 62.
[4] See response to OUCC Set 23-010, Attachment B.
[5] See Petitioner's Exhibit LEM-3 (Revised), Adjustment DA-2.
[6] See Petitioner's Exhibit LEM-1 (Revised), p. 32.
[7] Petitioner's Exhibit JJS-1, p. 10.
[8] Id., pp. 12 and 16.
[9] Id., p. 9.
[10] Petitioner's Exhibit JJS-1, p.36.

1 assumed a 60 year life for the steam plant and 40 years for the combustion turbine for the
2 recently acquired Sugar Creek facility.[11]

3 Mr. Spanos used an Inflated Future Cost Approach to study net salvage for NIPSCO's
4 mass property accounts. Mr. Spanos used the terminal net salvage estimates from specific
5 demolition studies conducted by Company witness Mr. Victor Ranalletta of Burns &
6 McDonnell ("B&M") for his terminal net salvage estimates for NIPSCO's generation
7 plants.[12] Although all of Mr. Ranalletta's estimates are in 2008 dollars, Mr. Spanos also
8 inflated Mr. Ranalletta's 2008 estimates to develop his generating plant depreciation rates.[13]
9 Mr. Spanos' explicit inflation adjustments more than doubled Mr. Ranalletta's 2008 values
10 from $354 million to $725 million.[14] Consequently, all of Mr. Spanos' futures net salvage
11 estimates incorporate inflation that has not been incurred. Finally, Mr. Spanos implemented
12 amortization accounting for certain common and general accounts.[15]

13 **Q: Did Mr. Spanos reflect any of NIPSCO's plans in his depreciation rates?**

14 A: Yes, the Company plans to retire D.H. Mitchell and Michigan City Units 2 and 3 in the near
15 future. Neither of these units have been operational for several years, however, they have not
16 yet been retired from the books. Mr. Spanos redistributed depreciation reserves to "assign
17 sufficient depreciation reserve to each of these units to account for the anticipated retirement
18 and the negative [terminal] net salvage for these units as set forth in the Burns & McDonnell

[11] Petitioner's Exhibit JJS-1, p. 19.
[12] Petitioner's Exhibit JJS-1, p. 15.
[13] See page 12 of Rannaletta Testimony and Petitioner's Exhibit JJS-2, p. 39.
[14] Response to OUCC 8-DEP-36, attached as Exhibit MJM-7.
[15] Petitioner's Exhibit JJS-1, p. 17.

1 studies such that no future depreciation expense will be assigned to these plants and the net
2 book value will be zero."[16]

3 **General Conclusions**

4 **Q: What do you conclude?**

5 A: I conclude that the Commission should not approve NIPSCO's request for a depreciation
6 expense increase. None of Mr. Spanos' proposed depreciation rates should be implemented
7 because Mr. Spanos' depreciation proposals perpetuate the methodological flaws included in
8 NIPSCO's last depreciation study. Mr. Spanos also perpetuates a myth that NIPSCO needs
9 to charge exorbitant excessive amounts to current ratepayers for future cost of removal. The
10 results of this myth have created a huge $892.7 million Regulatory Liability owed to
11 ratepayers for future cost of removal for both electric and gas operations.[17]

12 Based on the Company's responses to OUCC 7-DEP-030 and 23-015, it appears that
13 even though NIPSCO collected this money in advance from ratepayers, Mr. Spanos did not
14 recognize these advance collections in his depreciation rates, nor did NIPSCO recognize
15 them as a rate base deduction. This is an egregious situation. The IURC should specifically
16 recognize the advance collections as a Regulatory Liability to be deducted from rate base
17 until returned to ratepayers or used for their intended purpose.
18

[16] Id., pp. 15-16, and response to OUCC 7-DEP-29.
[17] See response to OUCC 23-023, Attachment A, p.5. Amount consists of $413.2 million for electric plant, $477.5 million for gas plant and $1.9 million for common plant. Also see response to OUCC 23-022.

OUCC Approach

Q: What was your approach to determining the appropriate depreciation rates?

A: I reviewed NIPSCO's filing, including Mr. Spanos' and several other Company witnesses' testimony and exhibits. I submitted several data requests of my own and reviewed the responses thereto. I conducted several independent analyses and calculations. On April 2, 2009, OUCC's Cynthia Pruitt and Jenny Sumner, my associate Margaret Kenney and I met NIPSCO's Michael Meyers at its headquarters in Merrillville, Indiana. We toured the following Company power plants: Mitchell, Bailly, Michigan City, and Schahfer. During the tour, Mr. Meyers and I updated and corrected my tour report from Cause No. 41746.

Steam Production Plant Lives

Q: Are there any differences between you and Mr. Spanos regarding Steam Production plant lives.

A: Both Mr. Spanos and I have used the life-span method for the Company's steam production plant accounts. The fundamental parameters are the probable retirement year estimates and the interim retirement rate assumptions. Interim retirements are the smaller retirements anticipated to occur prior to the attainment of the final retirement year. I have accepted all of Mr. Spanos' interim retirement assumptions.

Q: Have you accepted all of Mr. Spanos' probable retirement year assumptions?

A: Yes, I have accepted all of Mr. Spanos' final retirement year assumptions. Although neither Mr. Spanos nor the Company could provide any support for his proposed life spans, I relied on my firm's National Study of U.S. Steam Generating Unit Lives – 50 MW and Greater ("National Study"). This study, included as Exhibit MJM-1, uses analytical techniques

generally accepted in the utility industry and a database maintained by the U.S. Department of Energy. The study concludes that U.S. Steam Generating Units 50 MW or greater are experiencing average life spans of approximately 60 years and that these spans are lengthening almost on a year-to-year basis. I also relied on our similar study of Other Production Plant units to support Mr. Spanos' life span recommendations in that function.[18]

Q: What further efforts did you make to ascertain the likely life span of NIPSCO's steam production units?

A: As indicated earlier, a team of people and I toured all of NIPSCO's steam production plants. One objective of the tour was to gain a similar level of knowledge and understanding of the plants and their operations as Mr. Spanos obtained during his plant tour. Another objective was to determine if there were any visual signs which would provide information as to a specific probable retirement year or if plant management personnel could provide any additional information relating to Mr. Spanos' probable retirement year estimates. We viewed the operations of the plants and discussed routine and long-term maintenance practices. We also discussed the types of maintenance and modernizations typically conducted and planned to be conducted at each plant. Exhibit MJM-2 is a report summarizing our tour.

Q: What did you observe?

A: Only two of NIPSCO's plants were operating during our tour. As indicated, Mitchell was standing idle with only a few security guards and an aircraft beacon light in operation. Mitchell is one of the plants NIPSCO proposes to retire in the near future. It also proposes to

[18] This study is also included in Exhibit MJM-1.

1 charge ratepayers for the demolition of the plant. Michigan City was also idle during our
2 tour. This was because the main coal conveyor had caught fire and was under repair during
3 our visit. We viewed Unit 12 at Michigan City, which NIPSCO does not intend to retire
4 anytime soon. We also viewed Units 2 and 3 at Michigan City, which NIPSCO intends to
5 retire. Although NIPSCO intends to retire these units, it is not clear that it intends to
6 demolish them since they are not obligated to do so and they are enclosed in a usable "old
7 building." The overall conclusion is that these plants appear to be very well managed. Steps
8 have been taken to properly maintain and modernize the plants, to improve efficiency and
9 operations, and to meet environmental concerns. None of the plant management personnel
10 with whom discussions were held were aware of any plans to demolish any of the plants.

11 **Q: What did you conclude?**

12 A: I was troubled by NIPSCO's inability to provide a single rational reason for retiring the
13 Mitchell plant. Just six months prior to shutting it down, NIPSCO's plant management told
14 me that it had no plans to retire the plant. Exhibit MJM-3 is a copy of the tour report from
15 my August 23, 2001 tour of NIPSCO's facilities to support my depreciation study in Cause
16 No. 41746. The report confirms that at the time the Mitchell Plant managers were not aware
17 of any plans to retire that plant.

18 **Q: Why do you think NIPSCO took the plant out of service?**

19 A: NIPSCO may have shut down the plant initially for temporary economic reasons, but my best
20 guess is that NIPSCO intended to sell the plant to the City of Gary, which would then
21 demolish the plant to extend an airport runway.

22 **Q: Why do you believe NIPSCO intended to sell the plant to Gary?**

A: I believe this because Gary tried to acquire the plant. In Cause No. 42643, the City of Gary filed a "Petition for Valuation of Certain Utility Property and Approval of the Acquisition of Such Property," in an attempt to acquire the D.H. Mitchell plant site. The City stated that it desired "to acquire the Mitchell Plant for the purpose of an expanded airport development, as well as commercial, residential and recreational development."[19] The City claimed that "it had a right to acquire the Mitchell Plant and that the Commission should establish the value of the Mitchell Plant for the purpose of such an acquisition in accordance with its current idle status and taking into consideration the fact that the property will be subject to environmental remediation before it can be used by the City as intended."[20]

In testimony, the then Mayor of Gary, Scott L. King, stated that unless an agreement could be reached with NIPSCO regarding the acquisition of the plant, the City intended to exercise its right to acquire the property under eminent domain. In addition, he testified that the City was not willing to make a payment to NIPSCO to acquire the Mitchell Plant site, as it believed that the Mitchell Plant is worthless in its present condition and status.[21]

Eventually the Company and Gary agreed to a Settlement wherein a third party transaction consultant would be retained to arrange for an insured fixed-price contract ("IFC") for the demolition of the Mitchell Plant and environmental remediation of the site to industrial standards. Gary and NIPSCO would then work cooperatively to identify governmental funding and alternative funding mechanisms for the IFC. If the governmental

[19] Cause No. 42643, Dismissal Order, Issued January 18, 2006, p. 3.
[20] Id.
[21] Id., p. 4.

funding and alternative funding mechanisms were sufficient to cover the full cost of the IFC and if NIPSCO was satisfied that no costs arising under the IFC will be borne by NIPSCO, its customers, its parent company or any of its affiliates, NPSCO would be obligated to transfer the Mitchell Plant to the City for a nominal amount.[22]

The OUCC opposed the settlement, stating that it "did not adequately address the concerns raised in the OUCC's case-in-chief about need, valuation, cost responsibility and whether the transfer was in the public interest."[23] The OUCC also noted that the Settlement did not contain adequate assurances that the ratepayers will not ultimately bear the costs associated with the transaction.[24]

Q: What was the outcome of that case?

A: The Commission did not adopt the Settlement, finding instead that it was not a valid contract under Indiana law.

> Based on our review of the evidence presented in this Cause, and our review of the express terms contained in the Settlement Agreement, it is apparent that there are too many important details missing for the Settlement Agreement to be viewed as a valid and legally binding contract under Indiana law. The uncertain and open ended nature of the Settlement Agreement presented in this Cause, while perhaps providing the basis for ongoing discussion between the City of Gary and NPSCO, is far from a final agreement that can appropriately be considered by the Commission.[25]

[22] Id., p. 10.
[23] Id., p. 13.
[24] Id.
[25] Id., p. 19.

1 The Commission dismissed the matter without prejudice.[26] This does not necessarily
2 mean that Gary has given up its pursuit of Mitchell. The area is still ripe for development,
3 and it would not be surprising if Gary and NIPSCO are still looking for a way to resolve the
4 situation in Gary's favor.

5 **Q: Is any of this problematic from a depreciation standpoint?**

6 A: Yes, Mr. Spanos proposes to include substantial future demolition costs in his depreciation
7 rates for both Mitchell and Michigan City Units 2 and 3. If Gary wants to demolish the
8 Mitchell plant, then Gary should demolish the plant. Otherwise, NIPSCO does not intend to
9 demolish either Mitchell or the Michigan City units unless the Commission approves Mr.
10 Spanos' proposal and forces ratepayers to incur a highly uneconomic and unnecessary cost.
11 It is uneconomic because it is the ultimate sunk cost. There is absolutely no payback
12 associated with such an expenditure.[27] It is unnecessary because NIPSCO does not have any
13 legal obligation to demolish the plants. That is one of the reasons it has recorded an $892.7
14 regulatory liability for cost of removal.

15 **Q: What do you recommend?**

16 A: The Commission should not allow <u>any</u> terminal decommissioning costs in the depreciation
17 rates for these plants. It would impose an unnecessary charge to ratepayers.

18

[26] Id., p. 21.
[27] I agree there will be some minor security and electricity savings at Mitchell, but not nearly enough to justify demolition.

1 **Q: What about the rest of the plants?**

2 A: NIPSCO does not have any plans to retire any of its other generating plants. This was
3 evident from our tour and from the Company's response to OUCC 8-DEP-070, which I have
4 attached as Exhibit MJM-4. From that perspective combined with the facts that NIPSCO
5 does not have any obligation to demolish any of its plants, and in fact will not demolish
6 Mitchell or the Michigan City units unless the IURC requires ratepayers to pay for the
7 demolition, no terminal demolition costs should be allowed.

8 At a minimum, the terminal decommissioning costs should be stated at no more than
9 their 2008 present value per Mr. Ranalletta, not the inflated values proposed by Mr. Spanos.
10 Later in my testimony, I will provide a more detailed discussion of the impropriety of
11 charging current ratepayers for un-incurred future inflation.

12 **Transmission and Distribution Plant Lives**

13 **Q: How did Mr. Spanos study the Transmission and Distribution Plant accounts?**

14 A: Mr. Spanos used the retirement rate actuarial method.

15 **Q: What is your approach?**

16 A: I studied all of the accounts using both the retirement rate method and the Geometric Mean
17 Turnover analyses in order to test and corroborate Mr. Spanos' proposals.

18 **Q: Do you agree with all of Mr. Spanos' proposals?**

19 A: No, I disagree with several of Mr. Spanos' proposals. In each case, he is proposing a life
20 which is too short, thus overstating the resulting depreciation expense.

21

1 **Q: What are your disagreements?**

2 A: The following table summarizes the disagreements regarding the Transmission and

3 Distribution accounts.

4 **Transmission and Distribution Differences**

	Account	Spanos	Majoros
355	Poles and Fixtures	50 R2	56 S0
356	OH Conductors & Devices	55 R2.5	75 L1.5
369.2	Underground Services	50 S2.5	63 S1.5
370.1	Customer Metering Stations	38 R2	58 L0.5
370.2	Meters	32 O1	38 O2
373	Street Lighting & Signals	30 R1	41 O2

5

6 **Q: Are you proposing your recommended lives to the Commission?**

7 A: No. As unusual is it sounds, I am not proposing my recommended lives in this case. That is

8 because the ELG and net salvage issues are so large in terms of dollars, I do not want to be

9 accused of piling on with additional reductions due to these life differences.

10 **General Plant Lives**

11 **Q: Are there any differences between Mr. Spanos and you in the General Plant function?**

12 A: I have accepted all of Mr. Spanos' proposals in the General Plant function.

13 **Equal Life Group**

14 **Q: Would you please explain Mr. Spanos' proposal regarding ELG?**

15 A: Yes. Mr. Spanos is proposing to adopt and retroactively apply the equal life group procedure

16 to all vintages. This represents a significant procedural change to NIPSCO's depreciation

17 rates, and suggests that the past procedure was incorrect. Consequently, Mr. Spanos has the

18 burden of demonstrating that his procedural change is required and that his retroactive

1 application of the change is appropriate. Based on my experience, the OUCC does not have
2 any specific burden to demonstrate that the current procedure should be continued.
3 NIPSCO's current depreciation rates were calculated using the average life group procedure
4 ("ALG"), also called the average service life ("ASL") procedure.[28]

5 **Q: Please explain the ALG procedure.**

6 A: The ALG procedure develops a single average depreciation rate which can be applied
7 without change over the entire life of an account. For example, assume the average service
8 life for Poles is estimated to be thirty years. The ALG procedure would result in a 3.33
9 percent depreciation rate (1/30) designed to recover the entire investment in Poles, i.e., those
10 retired prior to the attainment of the thirty year average service life as well as those in service
11 beyond the thirty year average service life.

12 **Q: Why does Mr. Spanos object to continuing the ALG procedure?**

13 A: I believe that Mr. Spanos would admit that the fundamental assumption under ALG is <u>full</u>
14 <u>recovery</u>. Consequently, I assume Mr. Spanos' primary challenge to the ALG procedure is
15 the averaging explicitly reflected in its use, i.e., the assumption that over recovery of assets
16 retired beyond the average service life of the group will offset under recovery of assets retired
17 before the average service life of the group. This is an undeniable assumption in the ALG
18 procedure. In the example above, ALG depreciation would assume that the under recoveries
19 would be offset by over recoveries of Poles living well beyond the average service life. But,
20 again the fundamental assumption under ALG is <u>full recovery</u>.

[28] See Response to OUCC 10-DEP-076 and 23-12.

1 **Q: What is the difference between ALG and ELG?**

2 A: The ELG procedure is a more precise application of the same life and retirement pattern
3 assumed in the ALG procedure. The ELG procedure statistically disaggregates the
4 anticipated retirements within vintages and then effectively establishes a multitude of
5 separate individual depreciation rates for each of the various individual life groups. In the
6 Poles example, separate rates would be established for the retirements anticipated to be
7 incurred each year.

8 **Q: If ELG is a more precise procedure than ALG, is ELG also more susceptible to error**
9 **than ALG?**

10 A: Yes, in my opinion, ELG is more susceptible to error than ALG.

11 **Q: Why is ELG more susceptible to error than ALG?**

12 A: First, ELG requires annual depreciation rate changes whereas ALG does not. Furthermore,
13 due to its precision, ELG is more susceptible to errors resulting from forecasting
14 inaccuracies.

15 **Q: Would you summarize the pros and cons regarding ELG and ALG?**

16 A: Yes. From a theoretical standpoint ELG has the benefit of being based on the assumption of
17 a more precise cost allocation assuming perfect foresight. On the other hand, ELG requires
18 annual depreciation rate changes and produces precisely the wrong answer as a result of
19 forecasting inaccuracies. ALG has the benefit of a constant depreciation rate, and also in my
20 opinion, a higher probability of producing a correct overall result notwithstanding forecasting
21 inaccuracies. In my opinion, there is no downside risk to the use of ALG, whereas ELG
22 presents significant downside risk, all of which is borne by ratepayers.

1 **Q: Is ELG necessary?**

2 A: ELG is not necessary. Both ALG and ELG assume full recovery. This Commission must
3 decide, therefore, whether the benefits of ELG are sufficient to adopt its use. From a
4 theoretical standpoint, ELG has some theoretical merit but so does ALG. From a practical
5 standpoint, ELG will produce a significant depreciation expense increase, merely from the
6 adoption and retroactive application of an unnecessary procedure change.

7 **Q: Do you recommend that ELG be adopted?**

8 A: No. There are negative aspects to the adoption of ELG and it is not necessary.

9 **Q: Does the USoA require the use of ELG?**

10 A: No, the USoA does not even mention ELG.

11 **Q: The IURC has approved ELG for other companies. If the Commission were to adopt**
12 **ELG for NIPSCO, do you agree with Mr. Spanos' implementation proposal?**

13 A: No. Mr. Spanos proposes to retroactively apply ELG to all prior vintages of plant in a
14 composite calculation, and then use the resulting ELG-based composite remaining life in a
15 remaining life rate calculation. This is an incorrect approach to the adoption of ELG and
16 creates an inappropriate, excessive and abrupt increase to depreciation expense.[29] In this
17 proceeding, the change would be an abrupt $24.1 million increase. Exhibit MJM-6 shows
18 the difference in Mr. Spanos' depreciation expense caused by his retroactive application of
19 ELG.

20 **Q: Why does a retroactive application of ELG cause an abrupt $24.1 million increase to**
21 **depreciation expense?**

[29] Exhibit MJM-5 is a copy of certain emails between Mr. Spanos and the Company. Based on these, I conclude that Mr. Spanos may have applied ELG only as an afterthought, but he specifically recognized the "big jump" that ELG caused.

A: The abrupt $24.1 million depreciation expense increase is caused primarily by the fact that NIPSCO has never used ELG in the past. Had NIPSCO always used ELG, its recorded book reserve would now be substantially higher as a result of the use of higher depreciation rates in the past. That is because ELG produces a pattern of depreciation rates very similar in appearance to accelerated depreciation; sum-of-the-years-digits or double-declining balance, for example.

Q: Please explain why the recorded book reserve is relevant to Mr. Spanos' retroactive application of ELG.

A: In addition to proposing ELG, Mr. Spanos is also proposing remaining life depreciation. Based on my experience in several cases in which Mr. Spanos was also involved, I know he is aware that the depreciation reserve level is a critical element in the calculation of remaining life rate. The higher the reserve, the lower the depreciation rate; conversely the lower the reserve, the higher the depreciation rate.

Mr. Spanos' retroactive application of ELG to all prior vintages produces a composite remaining life for those vintages which is inconsistent with past ALG depreciation rates and therefore inconsistent with NIPSCO's current book depreciation reserve levels.

Q: What is the practical consequence of Mr. Spanos' retroactive application of ELG to all prior vintages?

A: The practical consequence is that Mr. Spanos' retroactive application of ELG creates a significant but fictitious depreciation reserve deficiency resulting merely from an unnecessary change to a depreciation grouping procedure. Once a fictitious reserve deficiency is created, Mr. Spanos' use of the remaining life technique accelerates

1 amortization of the fictitious reserve deficiency. The amortization of the fictitious reserve
2 deficiency causes the abrupt $24.1 million depreciation expense increase.

3 **Q: What is the correct way to adopt ELG?**

4 A: The most well known application of the ELG procedure was in the telecommunications
5 industry. Many FCC subject companies made similar proposals for retroactive application of
6 ELG, and all were summarily rejected. They were rejected due to the reserve situations
7 described above. The FCC recognized that ELG creates a spike in revenue requirements just
8 as Mr. Spanos' proposal does in this proceeding. The FCC's initial approach to ELG
9 implementation was to allow it only on a going forward vintage basis and furthermore
10 phased-in by groups of accounts over a series of years. At one point, the FCC was allowing
11 implementation of ELG by applying it to one-half of the gross additions for the year
12 immediately following the study date. For example, if a study was dated December 31, 1990,
13 ELG would be allowed on one-half of the estimated 1991 additions. That practice was
14 abandoned and any carrier subsequently applying for ELG would not see its effects until its
15 study actually contained ELG vintages. For example, if ELG was approved as a result of a
16 1990 study, the first ELG vintage would be 1991. The Company would receive the benefit
17 either in its next regularly scheduled depreciation study or in a technical update.

18 **Q: If ELG is approved, what do you recommend?**

19 A: If ELG is approved, I recommend that it not be applied retroactively. If ELG is approved, I
20 recommend that the FCC's approach be adopted, i.e., the first ELG vintage would be 2008
21 for the purposes of the next depreciation study. Otherwise, the Commission must abandon
22 the remaining-life technique. That is because the ELG remaining life for prior vintages will

be inconsistent with the Commission-approved procedures applied to those vintages. The result of the remaining life technique will be a punishment in the form of an unnecessary increase to current ratepayers for using an approved procedure in the past. I also recommend that NIPSCO be required to file depreciation studies every three (3) years to ensure that the ELG rates are properly managed.

Mr. Spanos' Cost of Removal Proposals

Q: Please explain "cost of removal."

A: The cost of providing utility service includes not only the costs of installing and operating utility plant, but also removing that plant where appropriate at the end of its useful life. Therefore, one of the components of a public utility depreciation rate is a current estimate of future cost of removal (or negative net salvage). This estimate is typically expressed as a ratio that is applied to the current plant balance to provide an estimate of the future cost of removal. This future cost is, in turn, charged to depreciation expense on a straight-line basis over the remaining life of the plant, just as the depreciation of plant investment is charged to expense. A cost of removal or negative net salvage ratio increases the overall depreciable cost base because it allocates a portion of the estimated future removal cost to each year of the asset's service life. This process is, by definition, accrual accounting.

Q: Do you object to this process?

A: No, I do not object to this process if properly applied.

Q: If you are not raising any objection to the general process of forecasting future costs of removal or net salvage, what does your testimony address and how is it different than what NIPSCO proposes?

A: My testimony focuses on the inclusion of future inflation in the cost of removal estimates. To that end, my discussion addresses accrual accounting, matching and intergenerational equity principles. I will provide a simple and straight-forward example demonstrating that the present value approach is the approach most consistent with these principles because it properly matches inflation expense to the periods incurred and eliminates the intergenerational inequity inherent in Mr. Spanos' approach. In other words, I have accepted Mr. Spanos' future cost of removal proposals at their face values. I have merely expressed them at their present value so current ratepayers will not be charged for future inflation that has not been incurred.

Both my approach and Mr. Spanos' approach would recover the same total amounts for plant in service today that will likely be removed from service twenty years from now. My approach would achieve the same straight-line pattern as Mr. Spanos' approach for recovery of the original plant investment. Both approaches would also achieve the same straight-line pattern for the present value of the estimated net salvage costs that will be incurred in 2029.[30] The only difference is the cost recovery pattern for the future inflation costs; I would have the annual amounts increase during the twenty-year period to reflect the effects of inflation (and permit NIPSCO customers to pay in inflated dollars), while Mr. Spanos would allocate the future inflation costs on a straight-line basis, an outcome that assigns a disproportionate share of those costs to current ratepayers.

Q: How did Mr. Spanos arrive at his net salvage or future cost of removal proposals?

[30] For example, Mr. Ranalletta's 2008 estimates rather than Mr. Spanos' inflated estimates.

A: For the generating plant accounts, Mr. Spanos inflated Mr. Ranalletta's estimates as discussed previously. Exhibit MJM-7 shows Mr. Spanos' inflation adjustments to Mr. Ranalletta's 2008 demolition cost estimates. For the mass property accounts, Mr. Spanos conducted a "traditional" historical net salvage analysis to estimate future net salvage ratios for each account. This is the same sort of analysis that I have been objecting to before the Public Service Commissions for many years now.

Q: Why do you object to Mr. Spanos' net salvage approach?

A: Mr. Spanos' approach is front-loaded in its treatment of future inflation costs. It increases the current estimate of future costs of removal for a substantial amount of future inflation. In other words, Mr. Spanos' approach charges current ratepayers on an undiscounted basis for future inflation, as described above. Mr. Spanos justifies this approach by claiming that charging current ratepayers for un-incurred future inflation is "accrual accounting." I disagree. Accrual accounting consists of matching costs to the periods in which they are incurred. Mr. Spanos' approach fails that fundamental test by front loading future inflation. That is why GAAP specifically precludes his approach.[31]

[31] For example, SFAS No. 143 requires that any legitimate future removal cost be expressed at its fair present value.

1 **Q: Why does Mr. Spanos' approach result in inflated future cost of removal estimates for**
2 **NIPSCO's mass property accounts?**
3 A: Mr. Spanos bases his mass property approach on the relationship of current cost of removal
4 expenditures in today's dollars versus the original cost of the plant being retired, calculating
5 a ratio of current cost of removal (in today's dollars) to original cost of plant (in historical
6 dollars). A substantial part of the current cost of removal represents past inflation
7 experienced during the period (often decades) between when the plant was first put in service
8 and when the removal costs were incurred. He then applies that ratio to today's plant
9 balances to project the future cost of removal. In this way, Mr. Spanos' calculation
10 extrapolates into the future all of the past inflation rather than the small portion actually
11 experienced during 2007, just as his explicit inflation adjustments increase Mr. Ranalletta's
12 2008 present value demolition cost estimates.
13 **Q: Does Mr. Spanos agree that his approach compares historical plant retirement dollars**
14 **with current cost of removal and gross salvage dollars and thus results in an estimate**
15 **which incorporates an assumed level of future inflation?**
16 A: Although he does not explicitly say so, he agrees.[32]
17 **Q: What is the effect of Mr. Spanos' approach?**
18 A: Mr. Spanos' inflated future cost of removal rates result in a $27.0 million annual charge for
19 future costs of removal versus the $9.3 million NIPSCO incurs on average.[33] This type of
20 difference is largely responsible for the $892.7 million cost of removal regulatory liability the

[32] Response to OUCC Set 8 DEP 052 and 053.

Company reports in its Annual 10-K Report.[34] In other words, as of December 31, 2008, NIPSCO has collected almost $892.7 million more from ratepayers than it has spent on actual cost of removal.

As shown in the table below, this regulatory liability has increased each year since 2006. This growth is almost entirely attributable to future inflation costs.

NIPSCO Regulatory Liability for Cost of Removal[35]

Year	Electric	Gas	Common	Total
2006	$ 418,739,525	$ 366,376,850	$ 2,220,135	$ 787,336,509
2007	381,670,920	446,347,571	2,027,084	830,045,576
2008	413,179,774	477,533,747	1,946,950	892,660,471

Accrual Accounting

Q: What is accrual accounting?

A: Accrual accounting recognizes or matches revenue to the periods earned and expenses to the periods incurred. Accrual accounting is the foundation of generally accepted accounting principles ("GAAP"). The directives issued by the Financial Accounting Standards Board (FASB), such as SFAS No. 143 and FIN 47 set forth GAAP.

Q: What is cash basis accounting?

A: Cash basis accounting recognizes revenues and expenses when received or disbursed rather than when earned or incurred.

[33] Response to OUCC Set 10 DEP 095 and OUCC Set 7-DEP-019, Attachment A.
[34] See response to OUCC Set 23-023, Attachment A, p. 5. Amount is total NIPSCO portion of NiSource regulatory liability.
[35] 2006 and 2007 data from response to OUCC Set 10 DEP-088. 2008 data from response to OUCC Set 23-023.

1 **Q: Does Mr. Spanos' approach constitute accrual accounting?**

2 A: Not to the extent it charges current ratepayers for the costs of future inflation that may not be
3 incurred for years, decades or at all. Accrual accounting would match those future inflation
4 costs to the ratepayers taking utility service at the time the inflation is incurred. Mr. Spanos'
5 approach does not match inflation costs to the periods incurred.

6 **Q: Do the relatively recent pronouncements of the Financial Accounting Standards Board**
7 **provide any useful guidance on these questions?**

8 A: I believe they do, even if the questions are arising here in a ratemaking proceeding and the
9 FASB pronouncements apply most directly to financial reporting requirements. But the
10 underlying principles of achieving appropriate "matching" through accrual accounting do not
11 change whether they arise in a ratemaking or financial reporting setting.

12 Mr. Spanos is no doubt familiar with the accounting prescribed in SFAS No. 143 and
13 FIN 47, which constitute GAAP. SFAS No. 143 was adopted to establish accounting
14 standards for recognition and measurement of a liability for an asset retirement obligation
15 and any associated asset retirement cost.[36] NIPSCO now estimates the "fair value" of its
16 estimated future retirement costs for financial reporting purposes. SFAS 143 provides that
17 where there are no quoted market prices to use for such estimating purposes, a "present
18 value" technique is often the best available substitute.[37] This present value technique
19 prescribed in SFAS 143 directs the discounting of the estimated future cash flows using
20 "credit-adjusted risk-free rate."

[36] SFAS No. 143, ¶ 1.

1 NIPSCO may argue that the Commission should not rely on SFAS No. 143 or FIN 47
2 for purposes of deciding ratemaking issues. For purposes of deciding what approach is most
3 consistent with principles of accrual accounting, however, I believe there is no better source
4 than SFAS 143 and the other FASB pronouncements that are, after all, the embodiment of
5 GAAP.

6 Under SFAS 143, companies are not required to report the absolute future value of
7 removal costs, but rather a "present value" of those future costs. For financial reporting
8 purposes, this better enables investors to assess a company's future asset retirement
9 obligations. For ratemaking, it serves a different purpose -- using a present value calculation
10 of the future costs of removal ensures that the future removal cost expenditure is measured in
11 a way that achieves a fair and correct approach to charge future inflation to customers during
12 an accounting period. My approach treats the test year as the relevant accounting period.

13 It's important to be clear about this. Utilities have in the past characterized my
14 recommendation of the present value approach as seeking to have Commissions adopt SFAS
15 143 for ratemaking purposes when, in fact, it was adopted for financial reporting purposes. I
16 am not asking the Commission to adopt SFAS 143 for ratemaking purposes. However, for
17 purposes of developing an appropriate estimate of the amount of future removal costs to
18 include in today's rates, the underlying principle is consistency with accrual accounting as set
19 forth in GAAP (of which SFAS 143 is a part), whether the estimate is to be used for financial
20 reporting purposes or for establishing a reasonable rate under cost-of-service ratemaking.

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[37] SFAS No. 143, ¶ 8.

1 The amount that should be charged to the accounting period is an appropriate share of the
2 present value of the future obligation. The Commission may choose to use something other
3 than the "credit-adjusted risk-free rate" described in SFAS No. 143 for calculating the
4 present value of the future obligation, but the underlying principle of accrual accounting
5 remains. In ratemaking, the accounting period is the test year, not the remaining life of the
6 plant.

7 **Q: Can you demonstrate that using the present value approach constitutes accrual**
8 **accounting and that Mr. Spanos' approach does not constitute accrual accounting?**

9 A: Yes. Exhibit MJM-8 is a chart I designed to demonstrate those facts. It is a simple single
10 asset example comparing Mr. Spanos' approach to collecting future inflation versus the
11 present value accrual approach. As you can see, both Mr. Spanos' approach and the present
12 value approach accumulate the same total amount for future removal costs by the end of the
13 asset's life. The difference is the rate of collection for future inflation costs. The present
14 value approach matches inflation to the periods incurred. Mr. Spanos' approach front-loads
15 future inflation costs into current periods, and by doing so overcharges ratepayers in the early
16 years and undercharges ratepayers in the later years. This flies in the face of the
17 "intergenerational equity" and accrual accounting concepts; it stands them on their heads.
18 The front-loading element of this approach is also why NIPSCO has an $892.7 million
19 regulatory liability for GAAP purposes.

20 **Q: Is your example intended to show rate base effects?**

21 A: No, the example demonstrates that accrual accounting matches inflation to the periods
22 incurred. Rate base is irrelevant to that demonstration.

Q: Is there any economic rationale that supports matching future inflation to the periods incurred?

A: Yes, the inflation-related portion of the future removal cost will be paid for with cheaper dollars in future years. In terms of nominal dollars, the amount paid appears higher, but in real (that is, inflation-adjusted) dollars, the same amount is paid now and in the future, all else equal. When it comes to future inflation costs, "straight-line" recovery should be measured in real dollars, not nominal dollars.

Q: Is Mr. Spanos' approach required under the Uniform System of Accounts ("USoA")?

A: No, nothing in the USoA requires depreciation rates to be based on inflated future costs, or to collect from today's ratepayers the costs of inflation that will not be experienced for years or even decades to come.

Q: Will ratepayers be harmed by Mr. Spanos' approach?

A: Yes. NIPSCO's ratepayers have to date paid in total $892.7 million more than the Company's actual cost of removal, with a substantial portion of that amount representing inflation costs that will not be incurred for years or decades to come. This is the effect of the Company's long-term use of the same approach Mr. Spanos is proposing in these cases.

Removing Inflation – Better Aligning Mr. Spanos' Approach with Accrual Accounting

Q: What adjustment is necessary to correct the flaw resulting from the mismatch of current removal dollars to historical retirement dollars?

A: In order to develop the *current* dollars needed to cover the future cost of removal, it is necessary to calculate the present value of Mr. Spanos' estimated future costs. The estimated future costs should be discounted to their present value using Mr. Spanos' proposed remaining lives and a reasonable estimate of the future inflation incorporated into his

estimates. In this case, I recommend using the ALG remaining lives Mr. Spanos has provided in response to OUCC Set 7 DEP-31, as opposed to the ELG remaining lives he proposes.

Q: Would discounting Mr. Spanos' cost of removal proposals back to present value better align his proposals with accrual accounting?

A: Yes, the costs would be correctly matched to future periods. Ratepayers in 2009 would bear the costs of 2009 inflation, but not inflation costs that will not be incurred until 2019, 2029, or even further into the future.

Q: What do you recommend?

A: I recommend discounting all of Mr. Spanos' inflated future cost of removal estimates to their present values.

Q: Have you properly calculated future net salvage ratios on a present value basis?

A: Yes, I have used Mr. Ranaletta's 2008 values, as shown in Exhibit MJM-7 for production plant accounts. Exhibit MJM-9, Schedule 3 contains calculations for the mass property accounts. I removed the inflation from each of Mr. Spanos' estimates. Using the Handy-Whitman Index for the North Central region, I measured the inflation incurred from 1984 to 2007, i.e., the 24 years Mr. Spanos included in his net salvage studies. I used the Handy Whitman indication to discount his proposals. All of these calculations take into account my previous recommendation to reject the unnecessary switch to ELG.

1 **Q: How do you propose to treat inflation that will occur between now and the next time**
2 **the Commission reviews the Company's depreciation rates?**
3 A: Given the over-collected status of the Company's regulatory liability for cost of removal, the
4 Commission could determine that no such adjustment is necessary and any shortfall in the
5 amounts collected in the next several years is already more than covered by the existing
6 reserves.
7 However, if the Commission wishes to make an adjustment to reflect current inflation
8 it could do so quite easily. The Commission could direct NIPSCO to file annual schedules
9 reflecting an increase consistent with current inflation, and the inflation adjustment would be
10 made annually between rate cases. Alternatively, the adjustment could be made each time
11 NIPSCO files for new depreciation rates.
12 **<u>IURC Should Recognize Regulatory Liability for Cost of Removal</u>**
13 **Q: Please explain the regulatory liability for cost of removal.**
14 A: To date NIPSCO has collected $892.7 million more than it has actually spent for future cost
15 of removal.[38] It has collected this excess because prior depreciation rates front-loaded un-
16 incurred future inflation, just as Mr. Spanos is proposing in this proceeding. Luckily SFAS
17 No. 143 requires NIPSCO to report this as a Regulatory Liability in its reports to
18 shareholders and the SEC.
19

[38] See response to OUCC Set 23-023, Attachment A, p. 5. Amount consists of $413.2 million for electric plant, $477.5 million for gas plant and $1.9 million for common plant. Also see response to OUCC 23-022.

Q: Did Mr. Spanos or any other NIPCSO witness identify the $892.7 million Regulatory Liability in its filing before the IURC?

A: No, although NIPSCO has informed its shareholders that it has this Regulatory Liability (refundable obligation to ratepayers) for the excess collections, neither Mr. Spanos nor any other Company witness revealed the Regulatory Liability in this filing.

Q: Why is it necessary for this Commission to officially recognize the Regulatory Liability?

A: The IURC should recognize officially the $892.7 million Regulatory Liability for the excess cost of removal for several reasons, but primarily because if it does not, NIPSCO is likely to eventually take the excessive collections over and above its actual cost of removal expenditures into its income. Ratepayers will lose and NIPSCO will gain this money. I cannot think of any outcome that is more anathema to the letter and spirit of regulatory ratemaking.

Q: Why is Regulatory Liability treatment required?

A: NIPSCO and virtually all other utilities consider amounts in accumulated depreciation, even excessive amounts, to be <u>their</u> money, i.e. capital recovery, with no refund obligation. It is certainly fair and reasonable for any Commission to recognize excessive cost of removal collections as a refundable Regulatory Liability until the utility spends them on their intended purpose.

Until the IURC provides it, there is no *regulatory* recognition of the liability; and there is no provision for a refund to ratepayers if NIPSCO does not spend the cost of removal amounts for the intended purpose.

In other words, nothing holds NIPSCO directly accountable for these excess collections from a regulatory standpoint. NIPSCO failed to mention the Regulatory Liability in its depreciation study and this case in general. Experience indicates that it is highly unlikely that these amounts will be spent for cost of removal in the magnitude they have been collected. Furthermore, even if it was highly probable that NIPSCO would spend all this money for cost of removal, it is fair and reasonable for the IURC to recognize the ratepayers' security interest in these monies until spent on their intended purpose. Otherwise, the money is at risk.

Q: Are there any practical reasons why the IURC should officially recognize the Regulatory Liability?

A: Yes. As I explained earlier, the book depreciation reserve level is an important factor in the calculation of remaining life depreciation rates; the lower the reserve, the higher the resulting depreciation rate. Originally, my assumption was that NIPSCO had included excess cost of removal collections in its book reserve and merely reclassified them to a Regulatory Liability for GAAP accounting purposes. Under those circumstances, I would have recommended that the Commission order NIPSCO to also reclassify the excess collections from accumulated depreciation to account 254- Other Regulatory Liabilities for ratemaking and regulatory reporting purposes.

Q: What is different about NIPSCO's case?

A: According to two data responses addressing and attempting to clarify the issue, I conclude that NIPSCO reclassified the excess collections out of accumulated depreciation to the Regulatory Liability account for GAAP purposes but may not have put them back to

accumulated depreciation for ratemaking purposes. Furthermore, Mr. Spanos may not have included these amounts in the reserves he used to calculate depreciation rates. That means that his depreciation rates may not have even recognized the excess collections. Exhibit MJM-10 contains the data responses that support this conclusion, although we are continuing our investigation and this portion of my testimony may be supplemented if further discovery confirms this fact. Normal remaining life depreciation would ensure that at least some part of the excess would be flowed back each year in the form of a lower depreciation rate, and rate base would be lower to the extent that all the money is not yet returned. Not only are ratepayers paying too much depreciation, NIPSCO's rate base is significantly overstated.

Q: Please explain the GAAP Regulatory Liability issue.

A: As I explained earlier, SFAS No. 143 addresses asset retirement obligations ("AROs") associated with long-lived plant. When a company has a legal ARO, SFAS No. 143 requires capitalization of the discounted fair value of the liability and depreciation as a component of the original asset cost. If it is determined, upon implementation that a regulated utility has already collected too much depreciation relating to the legal ARO, the utility must report the excess as a Regulatory Liability.[39]

In addition, if a utility does not have a legal obligation to incur asset retirement costs, even though it has previously collected money embedded in depreciation rates[40], SFAS No. 143 (and the SEC) also requires reporting of that excess as a Regulatory Liability.[41] In

[39] SFAS No. 143.
[40] FERC defined these amounts as "non-legal AROs" meaning that the utilities do not have actual legal obligations to incur the costs.
[41] Id., paragraph B.73.

other words, if a regulated utility has collected future cost of removal in its depreciation rates, but does not and never will have a legal obligation to spend the money; it must segregate these excesses and report them as a Regulatory Liability.[42] As a result, SFAS No. 143 identified and highlighted NIPSCO's (and other utilities') prior excess collections for future cost of removal.

Q: How does GAAP define a Regulatory Liability?

A: SFAS No. 71 – Accounting for the Effects of Certain Types of Regulation defines regulatory liabilities from a GAAP perspective. I have summarized Paragraph 11, below. It provides the GAAP definition of a Regulatory Liability. Please pay particular attention to paragraphs 11 and 11.b.

SFAS No. 71 – Regulatory Liabilities[43]

> 11. Rate actions of a regulator can impose a liability on a regulated enterprise. Such liabilities are usually obligations to the enterprise's customers. The following are the usual ways in which liabilities can be imposed and the resulting accounting:
>
> a. A regulator may require refunds to customers.
>
> b. A regulator can provide current rates intended to recover costs that are expected to be incurred in the future with the understanding that if those costs are not incurred future rates will be reduced by corresponding amounts. If current rates are intended to recover such costs and the regulator requires the enterprise to remain accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose, the enterprise shall not recognize as revenues amounts charged pursuant to such rates. Those amounts shall be

[42] Id., paragraph B.73.
[43] SFAS No. 71, paragraph 11. Only the first sentence of each subparagraph is included.

recognized as liabilities and taken to income only when associated costs are incurred.

c. A regulator can require that a gain or other reduction of net allowable costs be given to customers over future periods. ...

Q: Does NIPSCO agree that its collections for non-legal AROs result in a Regulatory Liability?

A: No, OUCC posed that question in DR 10-097. NIPSCO responded that "NIPSCO does not agree that this constitutes a regulatory liability for regulatory purposes in Indiana," and "NIPSCO does not agree that this amount is a refundable obligation to ratepayers."[44]

Q: What do you recommend?

A: These amounts are dollars already collected from ratepayers for future cost of removal. There is no reason that the utility should be entitled to keep these dollars if it turns out they are never spent on their intended purpose, i.e., future costs of removal. It is obvious that the funds represent a refundable liability to ratepayers until spent on their intended purpose. Now that SFAS No. 143 has identified them, they should be recognized as the Regulatory Liability they are.

The OUCC believes that the IURC should specifically recognize that NIPSCO has an $892.7 million Regulatory Liability for these amounts. This will result in equivalent GAAP and regulatory accumulated depreciation and Regulatory Liability amounts for "non-legal" cost of removal.[45] NIPSCO's $892.7 million collection is a substantial amount of money.

[44] Response to OUCC 10-DEP-097.
[45] The phrase "non-legal" emanates from the FERC's Order No. 631. It is used to distinguish legally required asset

1 By definition, the Company has collected but not spent $892.7 million for cost of removal.
2 Therefore, the Commission should protect this amount in USoA account 254-Other
3 Regulatory Liabilities. Without this protection, current and future ratepayers face the strong
4 possibility of losing substantial prepaid funds they have submitted to the Company for future
5 cost of removal.

6 **Q: Why is it necessary that the IURC specifically protect these amounts on behalf of**
7 **ratepayers?**

8 A: Only the IURC has the ability and authority to protect the amounts. If the IURC does not
9 exercise its authority in this area, the excess collections will remain unprotected and subject
10 to loss by ratepayers. The ratepayers' loss will be NIPSCO's gain – dollar for dollar.

11 **Q: Does NIPSCO believe that its shareholders own the $892.7 million?**

12 A: Yes, it does. NIPSCO considers every penny of the $892.7 million to be shareholders'
13 capital, even though it did not incur the cost. The money is clearly at risk.

14 **Q: Do you have any recent evidence to corroborate the money is at risk?**

15 A: Yes, the telephone industry took $11.5 billion of its excess collections into equity when
16 alternative regulation was adopted. Furthermore, there is a major accounting change on its
17 way that may put the $892.7 million into further jeopardy. Exhibit MJM-11 contains two
18 recent articles from the Public Utilities Fortnightly.[46] The first article is by Mr. Ferguson
19 who is a depreciation witness that regularly testifies on behalf of utilities and regularly
20 advocates that they continue to collect the excess cost of removal I have discussed. In

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retirement obligations ("AROs") from those which lead to the cost of removal Regulatory Liability discussed above. Importantly, the phrase "non-legal" should not be construed to imply any "illegality."

[46] John Ferguson, "Fixing Depreciation Accounting", Public Utility Fortnightly, October 2008, pp. 16-20 and Scott

1 November 2008, Mr. Ferguson expressed his true sentiments: he proposes that when these
2 companies move to a new set of accounting standards, International Financial reporting
3 Standards ("IFRS") the utilities should transfer the regulatory liabilities to their equity
4 accounts. In the second article, Mr. Hartman from the accounting firm of Ernst & Young
5 says the same thing.

6 **Q: Is IFRS something new?**

7 A: The accounting profession and the SEC have been considering a switch from GAAP to IFRS
8 for some time.

9 **Q: What will be the effect?**

10 A: In my opinion, what GAAP has brought – i.e., identification of the SFAS No. 143 Regulatory
11 Liability - IFRS will take away by transferring it to equity.

12 **Q: But won't that be merely for financial purposes?**

13 A: Once that money is taken into income, there is no longer any remedy for ratepayers. In my
14 non-legal opinion, NIPSCO will consider any regulatory attempt in the future to recover the
15 money, whether through depreciation or otherwise, as a "taking" of property or "confiscation
16 of capital," and they will point to the world's accounting profession as authoritative
17 recognition of the amount as "their" money.

18

Hartman, "Ready for IFRS?", Public Utility Fortnightly, January 2009, pp. 10-16.

1 **Q: Does NIPSCO acknowledge that IFRS is coming?**

2 A: Yes, Exhibit MJM-12 is NIPSCO's response to OUCC 20-001 in which it states "The
3 adoption of IFRS will be managed by the NiSource Accounting Research Department."

4 **Q: Have any other Commissions recognized non-legal AROs as a Regulatory Liability?**

5 A: Yes. Recently, in Docket No. A.04-12-014, involving Southern California Edison Company,
6 the California Public Utilities Commission specifically recognized that Company's non-legal
7 ARO collections as a Regulatory Liability.

8 **Summary**

9 **Q: Have you summarized your recommendations?**

10 A: Yes. Exhibit MJM-9, Schedules 1 and 2 show my recommended depreciation rates. These
11 were calculated as of December 31, 2007 consistent with Mr. Spanos' calculations. In
12 addition, I have calculated depreciation rates for the new Sugar Creek plant. Because I did
13 not have the data necessary to calculate remaining life rates for Sugar Creek, I have
14 calculated whole-life rates, using 60 years for steam production and 40 years for other
15 production and the present value of Mr. Spanos' proposed net salvage estimates. The table
16 below compares my annual accruals with those proposed by Mr. Spanos.

	Electric	Common	Sugar Creek	Total
NIPSCO Proposed[47]	$ 160,291,823	$ 35,635,828	$ 5,823,487	$ 201,751,138
OUCC Recommended[48]	106,687,713	35,321,386	2,677,388	144,686,487
Decrease	$ 53,604,110	$ 314,442	$ 3,146,099	$ 57,064,651

17

[47] See calculations provided in response to OUCC Set 7 DEP-019. Sugar Creek amount calculated using Spanos rates and original cost provided in response to OUCC Set 23-010.
[48] Exhibit MJM-5 Schedules 1 and 2.

1 Based on plant in service as of December 31, 2007, I recommend a $57.1 million decrease in
2 depreciation expense over Mr. Spanos' proposed amount.
3 Schedule 6 of Exhibit MJM-9 applies my rates to the plant balances used in the
4 calculation of the Company's proposed depreciation expense adjustments - Exhibit LEM-3
5 (revised), Adjustments DA-2 and SCDA-7. Using these plant balances, my rates result in a
6 $58.0 million reduction to NIPSCO's depreciation expense adjustment DA-2.
7 Finally, I recommend that the IURC specifically recognize NIPSCO's $892.7 million
8 Regulatory Liability for ratemaking and regulatory reporting purposes. The electric portion
9 of this regulatory liability is $413.2 million.
10 **Q: Does this conclude your testimony?**
11 A: Yes, it does.

VERIFICATION

Washington,)
) ss:
DISTRICT OF COLUMBIA)

The undersigned, **Michael J. Majoros, Jr.**, under penalties of perjury and being first duly sworn on his oath, says that he is a **Consultant** of **Snavely King Majoros O'Connor & Bedell, Inc.**, a Consultant for the Indiana Office of Utility Consumer Counselor; and in the matter of Cause No. 43526 that he caused to be prepared and read the foregoing that the representations set forth therein are true and correct to the best of his knowledge, information and belief.

Dated: May 5, 2009

By: Michael J. Majoros

Subscribed and sworn to before me, a Notary Public, this 8th day of May 2009.

Angel L. Finch
Signature

Angel L. Finch
Printed Name

My Commission Expires: March 14, 2011

Michael J. Majoros, Jr.

Experience

Snavely King Majoros O'Connor & Bedell, Inc.

Vice President and Treasurer (1988 to Present)
Senior Consultant (1981-1987)

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory federal and state regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. His testimony has encompassed a wide array of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has also provided consultation to the U.S. Department of Justice and appeared before the U.S. EPA and the Maryland State Legislature on matters regarding the accounting and plant life effects of electric plant modifications and the financial capacity of public utilities to finance environmental controls. He has estimated economic damages suffered by black farmers in discrimination suits.

Van Scoyoc & Wiskup, Inc., *Consultant (1978-1981)*

Mr. Majoros conducted and assisted in various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr. Majoros provided onsite management accounting and controllership assistance to a municipal electric and water utility. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company), and he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM 80-42.

Handling Equipment Sales Company, Inc.

Controller/Treasurer (1976-1978)

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

Ernst & Ernst, *Auditor (1973-1976)*

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

University of Baltimore - *(1971-1973)*

Mr. Majoros was a full-time student in the School of Business.

During this period Mr. Majoros worked consistently on a part-time basis in the following positions: Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M. Carney & Co., CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards.

Central Savings Bank, *(1969-1971)*

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

Education

University of Baltimore, School of Business, B.S. – Concentration in Accounting

Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.

"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990.

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.

"Impaired Assets Under SFAS No. 121," National Association of State Utility consumer Advocates, 1996 Mid-Year Meeting, 1996.

"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.

"Local Exchange Carrier Depreciation Reserve Percents," with Richard B. Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001

"Rolling Over Ratepayers," Public Utilities Fortnightly, Volume 143, Number 11, November, 2005.

"Asset Management – What is it?," American Water Works Association, Pre-Conference Workshop, March 25, 2008.

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Date	Jurisdiction / Agency	Docket	Utility
		Federal Courts	
2005	US District Court, Northern District of AL, Northwestern Division 55/56/57/	CV 01-B-403-NW	Tennessee Valley Authority
		State Legislatures	
2006	Maryland General Assembly 61/	SB154	Maryland Healthy Air Act
2006	Maryland House of Delegates 62/	HB189	Maryland Healthy Air Act
		Federal Regulatory Agencies	
1979	FERC-US 19/	RP79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority
2003	FERC 48/	RM02-7	All Utilities
2003	FCC 52/	03-173	All LECs
2003	FERC 53/	ER03-409-000, ER03-666-000	Pacific Gas and Electric Co.
		State Regulatory Agencies	
1982	Massachusetts 17/	DPU 557/558	Western Mass Elec. Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co.
1983	New Jersey 1/	815-458	New Jersey Bell Tel. Co.
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia 7/	785	Potomac Electric Power Co.
1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist. Of Columbia 7/	798	C&P Tel. Co.
1984	Pennsylvania 13/	R-832316	Bell Telephone Co. of PA
1984	New Mexico 12/	1032	Mt. States Tel. & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel. & Telegraph
1984	Colorado 11/	1655	Mt. States Tel. & Telegraph

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1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Edison Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Suburban Water Co.
1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.
1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.
1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.
1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co.

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1994	Iowa 6/	RPU-93-9	U.S. West – Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm. Suburban Water Corp.
1995	Connecticut 25/	94-10-03	So. New England Telephone
1995	Connecticut 25/	95-03-01	So. New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell
1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa
1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech – Michigan
1997	Michigan 28/	U-112 81	GTE North
1997	Wyoming 27/	7000-ztr-96-323	US West – Wyoming
1997	Iowa 6/	RPU-96-9	US West – Iowa
1997	Illinois 28/	96-0486-0569	Ameritech – Illinois
1997	Indiana 28/	40611	Ameritech – Indiana
1997	Indiana 27/	40734	GTE North
1997	Utah 27/	97-049-08	US West – Utah
1997	Georgia 28/	7061-U	BellSouth – Georgia
1997	Connecticut 25/	96-04-07	So. New England Telephone
1998	Florida 28/	960833-TP et. al.	BellSouth – Florida
1998	Illinois 27/	97-0355	GTE North/South
1998	Michigan 33/	U-11726	Detroit Edison
1999	Maryland 8/	8794	Baltimore Gas & Electric Co.
1999	Maryland 8/	8795	Delmarva Power & Light Co.
1999	Maryland 8/	8797	Potomac Edison Company
1999	West Virginia 2/	98-0452-E-GI	Electric Restructuring
1999	Delaware 24/	98-98	United Water Company
1999	Pennsylvania 3/	R-00994638	Pennsylvania American Water
1999	West Virginia 2/	98-0985-W-D	West Virginia American Water
1999	Michigan 33/	U-11495	Detroit Edison
2000	Delaware 24/	99-466	Tidewater Utilities
2000	New Mexico 34/	3008	US WEST Communications, Inc.
2000	Florida 28/	990649-TP	BellSouth -Florida
2000	New Jersey 1/	WR30174	Consumer New Jersey Water
2000	Pennsylvania 3/	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania 3/	R-0005212	Pennsylvania American Sewerage
2000	Connecticut 25/	00-07-17	Southern New England Telephone
2001	Kentucky 36/	2000-373	Jackson Energy Cooperative
2001	Kansas 38/39/40/	01-WSRE-436-RTS	Western Resources
2001	South Carolina 22/	2001-93-E	Carolina Power & Light Co.
2001	North Dakota 37/	PU-400-00-521	Northern States Power/Xcel Energy
2001	Indiana 29/41/	41746	Northern Indiana Power Company

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2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop.
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban
2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Kentucky 36/	2001-244	Fleming Mason Electric Coop.
2002	Nevada 43/	01-11031	Sierra Pacific Power Company
2002	Georgia 27/	14361-U	BellSouth-Georgia
2002	Alaska 44/	U-01-34,82-87,66	Alaska Communications Systems
2002	Wisconsin 45/	2055-TR-102	CenturyTel
2002	Wisconsin 45/	5846-TR-102	TelUSA
2002	Vermont 46/	6596	Citizen's Energy Services
2002	North Dakota 37/	PU-399-02-183	Montana Dakota Utilities
2002	Kansas 40/	02-MDWG-922-RTS	Midwest Energy
2002	Kentucky 36/	2002-00145	Columbia Gas
2002	Oklahoma 47/	200200166	Reliant Energy ARKLA
2002	New Jersey 1/	GR02040245	Elizabethtown Gas Company
2003	New Jersey 1/	ER02050303	Public Service Electric and Gas Co.
2003	Hawaii 42/	01-0255	Young Brothers Tug & Barge
2003	New Jersey 1/	ER02080506	Jersey Central Power & Light
2003	New Jersey 1/	ER02100724	Rockland Electric Co.
2003	Pennsylvania 3/	R-00027975	The York Water Co.
2003	Pennsylvania /3	R-00038304	Pennsylvania-American Water Co.
2003	Kansas 20/ 40/	03-KGSG-602-RTS	Kansas Gas Service
2003	Nova Scotia, CN 49/	EMO NSPI	Nova Scotia Power, Inc.
2003	Kentucky 36/	2003-00252	Union Light Heat & Power
2003	Alaska 44/	U-96-89	ACS Communications, Inc.
2003	Indiana 29/	42359	PSI Energy, Inc.
2003	Kansas 20/ 40/	03-ATMG-1036-RTS	Atmos Energy
2003	Florida 50/	030001-E1	Tampa Electric Company
2003	Maryland 51/	8960	Washington Gas Light
2003	Hawaii 42/	02-0391	Hawaiian Electric Company
2003	Illinois 28/	02-0864	SBC Illinois
2003	Indiana 28/	42393	SBC Indiana
2004	New Jersey 1/	ER03020110	Atlantic City Electric Co.
2004	Arizona 26/	E-01345A-03-0437	Arizona Public Service Company
2004	Michigan 27/	U-13531	SBC Michigan
2004	New Jersey 1/	GR03080683	South Jersey Gas Company
2004	Kentucky 36/	2003-00434,00433	Kentucky Utilities, Louisville Gas & Electric
2004	Florida 50/ 54/	031033-EI	Tampa Electric Company
2004	Kentucky 36/	2004-00067	Delta Natural Gas Company

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2004	Georgia 23/	18300, 15392, 15393	Georgia Power Company
2004	Vermont 46/	6946, 6988	Central Vermont Public Service Corporation
2004	Delaware 24/	04-288	Delaware Electric Cooperative
2004	Missouri 58/	ER-2004-0570	Empire District Electric Company
2005	Florida 50/	041272-EI	Progress Energy Florida, Inc.
2005	Florida 50/	041291-EI	Florida Power & Light Company
2005	California 59/	A.04-12-014	Southern California Edison Co.
2005	Kentucky 36/	2005-00042	Union Light Heat & Power
2005	Florida 50/	050045 & 050188-EI	Florida Power & Light Co.
2005	Kansas 38/ 40/	05-WSEE-981-RTS	Westar Energy, Inc.
2006	Delaware 24/	05-304	Delmarva Power & Light Company
2006	California 59/	A.05-12-002	Pacific Gas & Electric Co.
2006	New Jersey 1/	GR05100845	Public Service Electric and Gas Co.
2006	Colorado 60/	06S-234EG	Public Service Co. of Colorado
2006	Kentucky 36/	2006-00172	Union Light, Heat & Power
2006	Kansas 40/	06-KGSG-1209-RTS	Kansas Gas Service
2006	West Virginia 2/	06-0960-E-42T, 06-1426-E-D	Allegheny Power
2006	West Virginia 2/	05-1120-G-30C, 06-0441-G-PC, et al.	Hope Gas, Inc. and Equitable Resources, Inc.
2007	Delaware 24/	06-284	Delmarva Power & Light Company
2007	Kentucky 36/	2006-00464	Atmos Energy Corporation
2007	Colorado 60/	06S-656G	Public Service Co. of Colorado
2007	California 59/	A.06-12-009, A.06-12-010	San Diego Gas & Electric Co., and Southern California Gas Co.
2007	Kentucky 36/	2007-00143	Kentucky-American Water Co.
2007	Kentucky 36/	2007-00089	Delta Natural Gas Co.
2008	Kansas 40/	08-ATMG-280-RTS	Atmos Energy Corporation
2008	New Jersey 1/	GR07110889	New Jersey Natural Gas Co.
2008	North Dakota 37/	PU-07-776	Northern States Power/Xcel Energy
2008	Pennsylvania 3/	A-2008-2034045 et al	UGI Utilities, Inc. / PPL Gas Utilities Corp.
2008	Washington 63/	UE-072300, UG-072301	Puget Sound Energy
2008	Pennsylvania 3/	R-2008-2032689	Pennsylvania-American Water Co. - Coatesville
2008	New Jersey 1/	WR08010020	NJ American Water Co.
2008	Washington 63/ 64/	UE-080416, UG-080417	Avista Corporation
2008	Texas 65/	473-08-3681, 35717	Oncor Electric Delivery Co.
2008	Tennessee 66/	08-00039	Tennessee-American Water Co.

Michael J. Majoros, Jr.

PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION RATE REPRESCRIPTION CONFERENCES

COMPANY	YEARS	CLIENT
Diamond State Telephone Co. 24/	1985 + 1988	Delaware Public Service Comm
Bell Telephone of Pennsylvania 3/	1986 + 1989	PA Consumer Advocate
Chesapeake & Potomac Telephone Co. - Md. 8/	1986	Maryland People's Counsel
Southwestern Bell Telephone – Kansas 20/	1986	Kansas Corp. Commission
Southern Bell – Florida 4/	1986	Florida Consumer Advocate
Chesapeake & Potomac Telephone Co.-W.Va. 2/	1987 + 1990	West VA Consumer Advocate
New Jersey Bell Telephone Co. 1/	1985 + 1988	New Jersey Rate Counsel
Southern Bell - South Carolina 22/	1986 + 1989 + 1992	S. Carolina Consumer Advocate
GTE-North – Pennsylvania 3/	1989	PA Consumer Advocate

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PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
West Virginia 2/	93-1165-E-D	Potomac Edison
West Virginia 2/	94-0013-E-D	Monongahela Power
New Jersey 1/	WR94030059	New Jersey American Water
New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co.
Maryland 8/	8796	Potomac Electric Power Co.
South Carolina 22/	1999-077-E	Carolina Power & Light Co.
South Carolina 22/	1999-072-E	Carolina Power & Light Co.
Kentucky 36/	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric
Kentucky 36/	2002-485	Jackson Purchase Energy Corporation

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Clients

1/ New Jersey Rate Counsel/Advocate	34/ New Mexico Attorney General
2/ West Virginia Consumer Advocate	35/ Environmental Protection Agency Enforcement Staff
3/ Pennsylvania OCA	36/ Kentucky Attorney General
4/ Florida Office of Public Advocate	37/ North Dakota Public Service Commission
5/ Toms River Fire Commissioner's	38/ Kansas Industrial Group
6/ Iowa Office of Consumer Advocate	39/ City of Witchita
7/ D.C. People's Counsel	40/ Kansas Citizens' Utility Rate Board
8/ Maryland's People's Counsel	41/ NIPSCO Industrial Group
9/ Idaho Public Service Commission	42/ Hawaii Division of Consumer Advocacy
10/ Western Burglar and Fire Alarm	43/ Nevada Bureau of Consumer Protection
11/ U.S. Dept. of Defense	44/ GCI
12/ N.M. State Corporation Comm.	45/ Wisc. Citizens' Utility Rate Board
13/ City of Philadelphia	46/ Vermont Department of Public Service
14/ Resorts International	47/ Oklahoma Corporation Commission
15/ Woodlake Condominium Association	48/ National Assn. of State Utility Consumer Advocates
16/ Illinois Attorney General	49/ Nova Scotia Utility and Review Board
17/ Mass Coalition of Municipalities	50/ Florida Office of Public Counsel
18/ U.S. Department of Energy	51/ Maryland Public Service Commission
19/ Arizona Electric Power Corp.	52/ MCI
20/ Kansas Corporation Commission	53/ Transmission Agency of Northern California
21/ Public Service Comm. – Nevada	54/ Florida Industrial Power Users Group
22/ SC Dept. of Consumer Affairs	55/ Sierra Club
23/ Georgia Public Service Comm.	56/ Our Children's Earth Foundation
24/ Delaware Public Service Comm.	57/ National Parks Conservation Association, Inc.
25/ Conn. Ofc. Of Consumer Counsel	58/ Missouri Office of the Public Counsel
26/ Arizona Corp. Commission	59/ The Utility Reform Network
27/ AT&T	60/ Colorado Office of Consumer Counsel
28/ AT&T/MCI	61/ MD State Senator Paul G. Pinsky
29/ IN Office of Utility Consumer Counselor	62/ MD Speaker of the House Michael Busch
30/ Unitel (AT&T – Canada)	63/ Washington Office of Public Counsel
31/ Public Interest Advocacy Centre	64/ Industrial Customers of Northwestern Utilities
32/ U.S. General Services Administration	65/ Steering Committee of Cities
33/ Michigan Attorney General	66/ City of Chattanooga

Snavely King Majoros O'Connor & Bedell, Inc.
National Study of U.S. Steam Generating Unit Lives
50 MW and Greater
2006 Study

I. Introduction

Snavely King Majoros O'Connor & Bedell, Inc. ("Snavely King") performed a study of U.S. Steam Generating Units Lives, 50 MW and Greater using analytical techniques generally accepted in the utility industry and a database maintained by the U.S. Department of Energy ("DOE"). Snavely King concludes that the lives of the U.S. Steam Generating Units (50 MW and Greater) are experiencing average life spans of approximately 60 years and these spans are lengthening almost on a year-to-year basis.

II. Database

The DOE's Energy Information Administration ("EIA") requires every owner of an electric utility generating plant to file a Form 860 describing the status of its generating facilities. From these reports, EIA maintains data on the installation and retirements of generating units around the country.

The data utilized in this study is available on the EIA's web site. The primary data used in Snavely King's study is located in the Form 860 database files[1]. The data was downloaded in several steps into a single Microsoft Access file and developed into inputs for Snavely King's actuarial analysis program.

III. Analysis

Snavely King initially study ("1999 Study") conducted a full band (1918-1999) resulting in a 54 L4 life and Iowa curve indication. Snavely King's initial ten-year band resulted in a 59 L4 indication and its initial rolling and shrinking band analysis showed trends toward longer lives – as long as 70 years.

Snavely King's 2000 update ("2000 Update") consisted of an analysis of the full band (1900-2000) and the most recent ten-year band (1991-2000) of data. The full band analysis had a best fit result of 60.5 L3, which indicates a 60 year life. The ten-year band best fit was a 59.5 R4, which indicates a 59 year life.

[1] Prior to 2001, the EIA Form-860 Database was split two parts, Form-860A (Annual Electric Generator Report – Utility) and Form-860B (Annual Electric Generator Report – Nonutility). After 2001 the EIA combined Form-860A and Form-860B in a single Form-860 database. During the consolidation of the two Form-860 databases, the EIA removed all listed retirements in the 2000 database. From 2001 onwards, the Form-860 database started listing new retirements and re-classification of generating units that retired prior to 2001. In some cases plants that where classified as operable during 2000 Study, but in fact had been retired where reclassified as retried in the EIA data after 2000

Snavely King's 2006 update ("2006 Update") consisted of an analysis of the full band (1900-2006) and the most recent ten-year band (1997-2006) of data. The full band analysis had a best fit result of 59 S3, which indicates a 59 year life. The ten-year band best fit was a 58 R4, which indicates a 58 year life.

IV. Additional Analyses

Additional analyses were performed: an expanded full band analysis, rolling band analysis and a shrinking band analysis. The results are discussed and set forth in tabular form below.

Expanded Full band Analysis

The expanded full band analysis held the initial year constant, but used cut off dates of 2005, 2004, 2003, and 2002. The actuarial analyses yielded the following results:

Expanded Full Band Analysis

Band	Life	Curve Type
1900-2006	59	S3
1900-2005	59	S3
1900-2004	59	S3
1900-2003	58	S3
1900-2002	58	S3

Rolling Band Analysis

The ten-year band analyses for these data sets provided a "rolling band" analysis. The results are summarized in the table below:

Rolling Band Analysis

Band	Life	Curve Type
1997-2006	58	R4
1996-2005	58	R4
1995-2004	58	R4
1994-2003	57	R4
1993-2002	58	L5

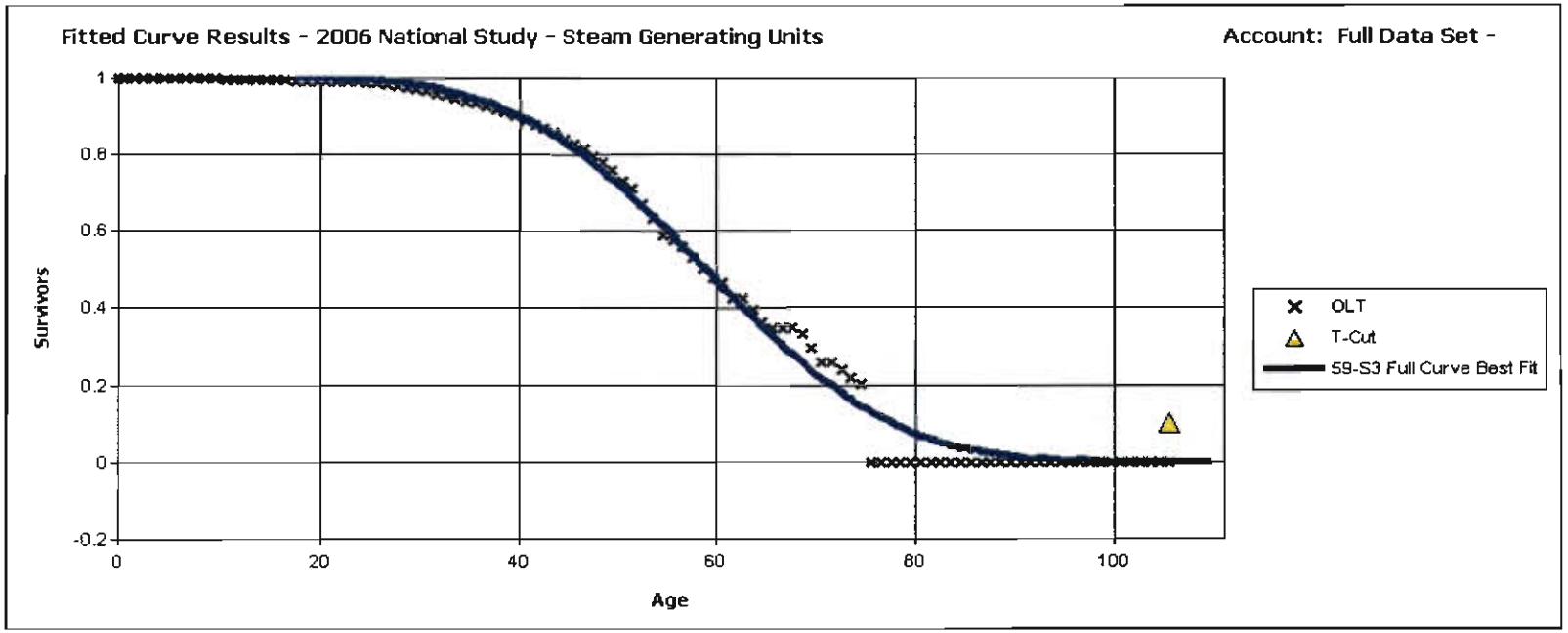
This indicates an increase in lives of generating units probably coincident with the wide spread introduction of life extension programs and the reduction in investment by utilities in new base load generating units.

Shrinking Band Analysis

Finally, Snavely King did a "shrinking band" analysis, in which the final 2000 year was held constant and the bands were continually shrunk.

Band	Width	Life	Curve Type
2002-2006	5	58	S4
1997-2006	10	58	R4
1992-2006	15	58	R4
1987-2006	20	58	R4
1982-2006	25	57	R4

The shrinking band analysis corroborated earlier results and conclusions.



Analytical Parameters

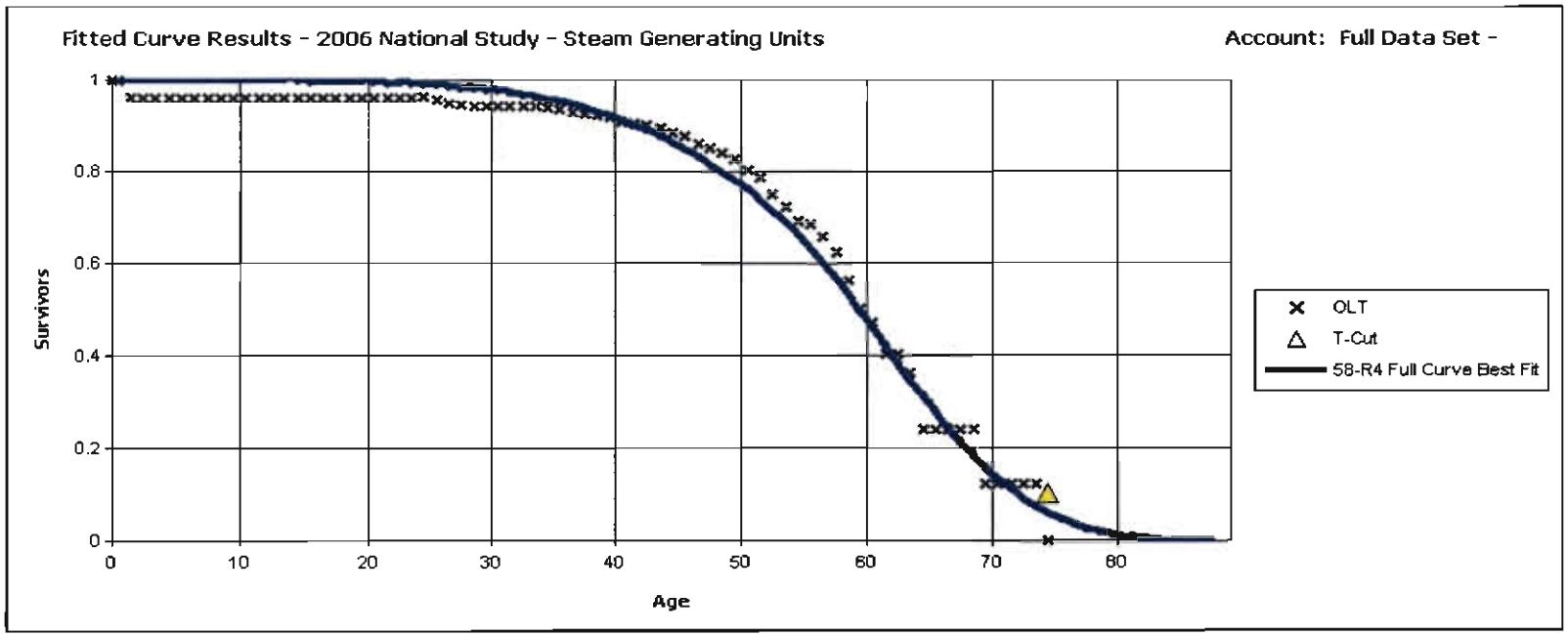
OLT Placement Band:	1900 - 2006
OLT Experience Band:	1900 - 2006
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	107.0

Best Fit Curve Results
2006 National Study - Steam Generating Units
Account: Full Data Set -

Curve	Life	Sum of Squared Differences
BAND	**1900 - 2006**	
S3	59.0	1,088.993
R3	58.0	1,191.623
R4	59.0	1,842.609
L4	60.0	1,933.157
R2.5	57.0	2,626.642
S4	60.0	2,945.066
S2	58.0	3,001.689
L3	60.0	4,685.997
L5	60.0	4,792.597
R2	56.0	5,141.857
S1.5	58.0	5,291.768
R5	60.0	6,978.197
S1	57.0	8,361.511
S5	60.0	8,635.656
R1.5	56.0	9,091.594
L2	59.0	11,655.665
S0.5	56.0	12,302.955
R1	54.0	14,155.627
L1.5	59.0	16,081.760
S6	60.0	16,416.956
S0	55.0	17,076.547
L1	58.0	21,483.080
R0.5	53.0	22,014.134
S-0.5	54.0	23,821.165
L0.5	58.0	26,917.624
O1	52.0	31,608.441
L0	58.0	33,241.913
SQ	59.0	35,783.144
O2	59.0	37,211.949
O3	74.0	56,138.776
O4	99.0	64,407.355

Analytical Parameters

OLT Placement Band:	1900 - 2006
OLT Experience Band:	1900 - 2006
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	107.0



Analytical Parameters

OLT Placement Band:	1900 - 2006
OLT Experience Band:	1997 - 2006
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	76.0

Best Fit Curve Results
2006 National Study - Steam Generating Units
Account: Full Data Set -

Curve	Life	Sum of Squared Differences
BAND	**1997 - 2006**	
R4	58.0	796.154
S4	59.0	1,228.560
L4	60.0	1,494.655
L5	60.0	1,573.579
R5	59.0	2,125.630
S3	59.0	2,248.330
R3	58.0	2,462.917
S5	60.0	2,995.326
R2.5	57.0	4,342.245
L3	62.0	4,543.176
S2	59.0	5,019.473
S1.5	59.0	6,970.160
R2	57.0	7,113.019
S6	60.0	7,142.851
L2	64.0	9,293.844
S1	60.0	9,504.726
R1.5	57.0	10,377.269
L1.5	65.0	12,051.102
S0.5	60.0	12,178.976
R1	58.0	14,444.787
S0	61.0	15,416.168
L1	66.0	15,578.356
L0.5	69.0	18,269.739
R0.5	60.0	19,361.207
S-0.5	63.0	19,508.344
L0	72.0	21,379.899
SQ	60.0	22,819.938
O1	66.0	24,312.779
O2	74.0	24,356.264
O3	100.0	27,717.940
O4	100.0	38,084.137

Analytical Parameters

OLT Placement Band:	1900 - 2006
OLT Experience Band:	1997 - 2006
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	76.0

Snavely King Majoros O'Connor & Bedell, Inc.
National Study of Other Production Unit Lives
2006 Study

I. Introduction

Snavely King Majoros O'Connor & Bedell, Inc. ("Snavely King") performed a study of U.S. Other Production Unit Lives[1] using analytical techniques generally accepted in the utility industry and a database maintained by the U.S. Department of Energy ("DOE"). Snavely King concludes that the lives of the U.S. Other Production Units are experiencing average life spans of approximately 50 years.

II. Database and Methodology

The DOE's Energy Information Administration ("EIA") requires every owner of an electric utility generating plant to file a Form 860 describing the status of its generating facilities. From these reports, EIA maintains data on the installation and retirements of generating units around the country.

The data utilized in this study is available on the EIA's web site. The primary data used in Snavely King's study is located in the Form 860 database files. The data was downloaded in several steps into a single Microsoft Access file and developed into inputs[2] for Snavely King's actuarial analysis program.

III. Analysis

Snavely King's 2006 update ("2006 Update") consisted of an analysis of the full band (1915-2006) and the most recent ten-year band (1997-2006) of data. The full band analysis had a best fit result of 50 S0.5, which indicates a 50 year life. The ten-year band best fit was a 50 R0.5, which indicates a 50 year life.

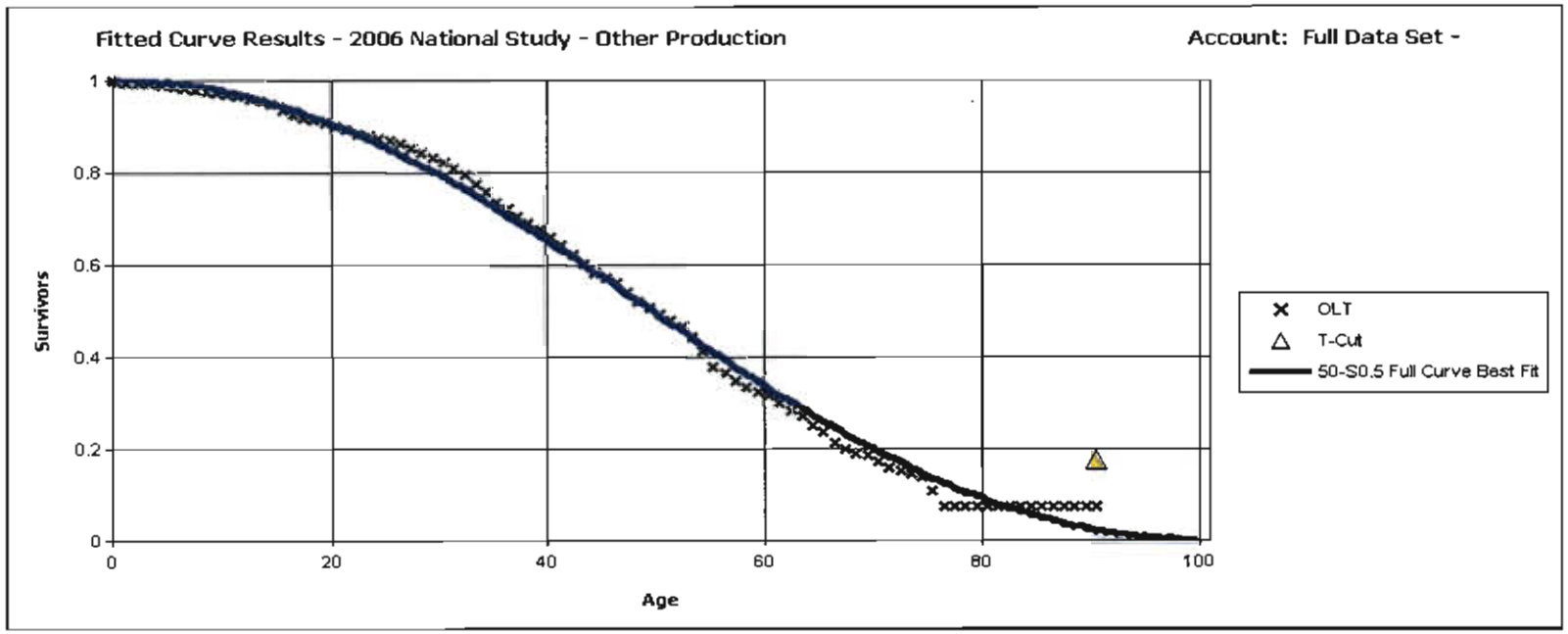
Finally, Snavely King preformed a "shrinking band" analysis, in which the final year was held constant and the bands were continually shrunk. The results are shown below.

Shrinking Band Analysis

Band	Width	Life	Curve Type
2002-2006	5	43	L0
1997-2006	10	50	R0.5
1992-2006	15	51	R1
1987-2006	20	50	R1
1982-2006	25	47	S0

[1] Other Production Units in this study are considered as Combusting (Gas) Turbines (including jet engine designs), Internal Combustion Engine (diesel, piston) and Combined Cycle Combustion Turbine generating units.

[2] Various sorts were made to refine the data and to remove bad data. For instance, some units listed as retired had no retirement dates indicated, etc.



Analytical Parameters

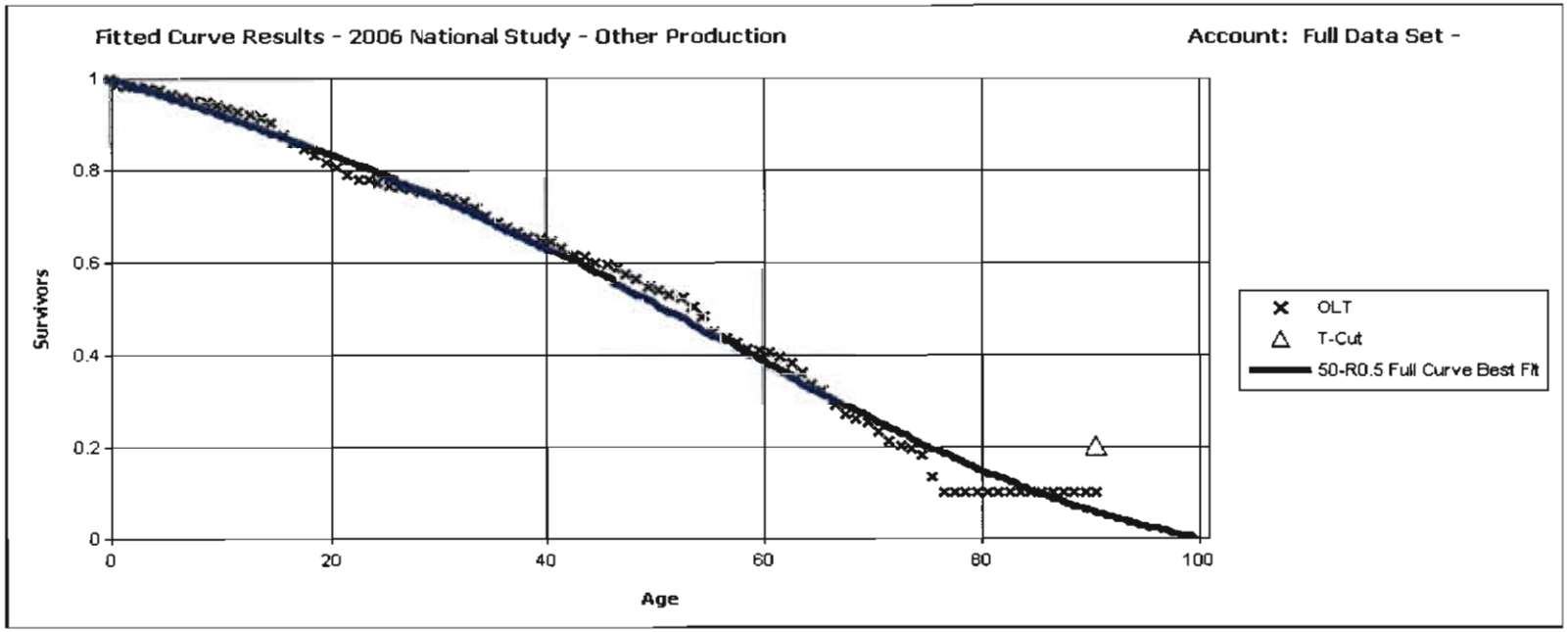
OLT Placement Band:	1915 - 2006
OLT Experience Band:	1915 - 2006
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	92.0

Best Fit Curve Results
2006 National Study - Other Production
Account: Full Data Set -

Curve	Life	Sum of Squared Differences
BAND	**1915 - 2006**	
S0.5	50.0	400.971
S1	50.0	432.746
R1.5	49.0	525.805
L2	51.0	661.377
L1.5	51.0	904.554
R1	49.0	1,007.595
S0	49.0	1,179.115
S1.5	50.0	1,180.871
R2	50.0	1,299.153
L1	51.0	2,121.823
L3	51.0	2,678.501
S2	51.0	2,701.452
R0.5	48.0	2,805.946
R2.5	50.0	2,869.604
S-0.5	48.0	3,171.055
L0.5	51.0	3,847.943
R3	50.0	5,616.852
L0	51.0	6,339.838
O1	47.0	6,416.110
S3	51.0	7,191.810
O2	52.0	8,244.710
L4	51.0	9,160.698
R4	51.0	12,042.745
S4	51.0	15,052.133
O3	64.0	17,366.231
L5	51.0	17,474.300
R5	51.0	21,444.751
O4	84.0	21,905.574
S5	51.0	23,899.724
S6	51.0	32,433.821
SQ	51.0	51,452.552

Analytical Parameters

OLT Placement Band:	1915 - 2006
OLT Experience Band:	1915 - 2006
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	92.0



Analytical Parameters

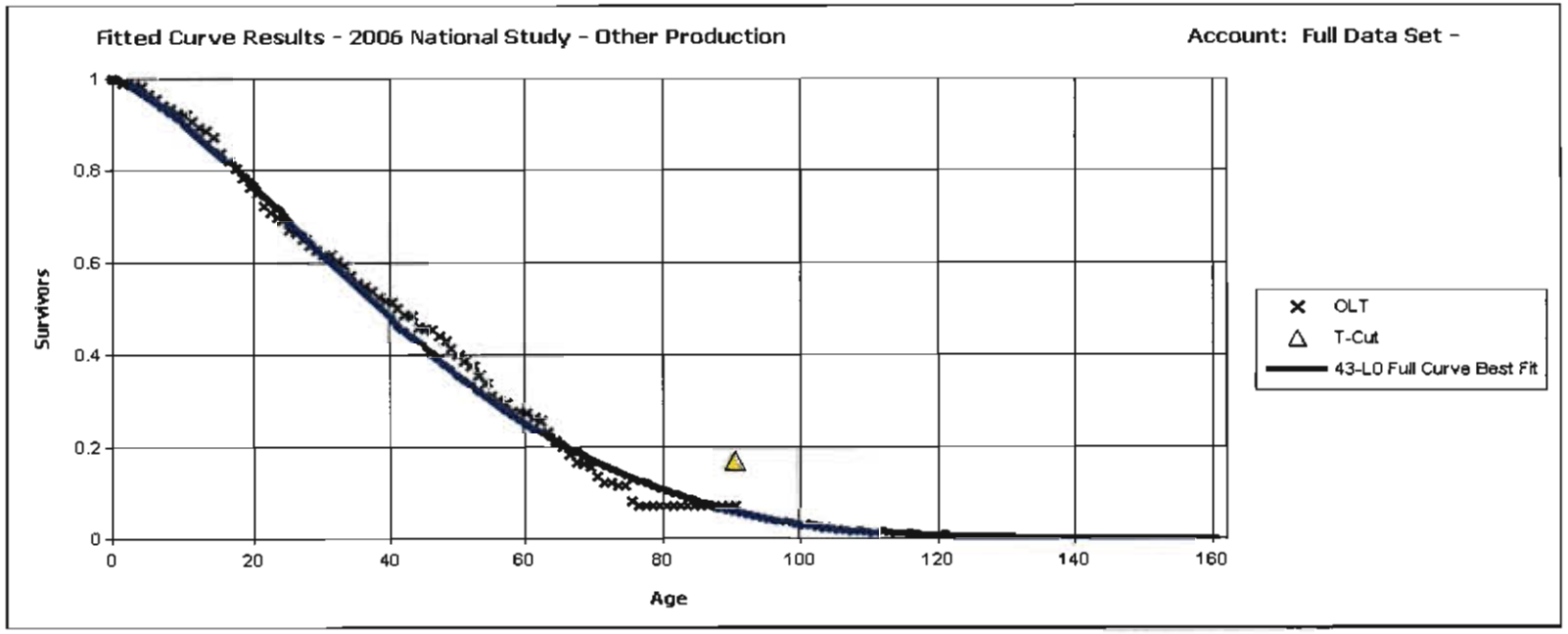
OLT Placement Band:	1915 - 2006
OLT Experience Band:	1997 - 2006
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	92.0

Best Fit Curve Results
2006 National Study - Other Production
Account: Full Data Set -

Curve	Life	Sum of Squared Differences
BAND	**1997 - 2006**	
R0.5	50.0	609.859
S-0.5	50.0	921.382
R1	51.0	932.246
S0	51.0	1,085.767
L0.5	52.0	1,881.619
L1	52.0	1,884.621
O1	49.0	2,029.514
S0.5	52.0	2,076.028
R1.5	52.0	2,432.511
L0	53.0	2,635.341
L1.5	53.0	2,756.984
O2	54.0	3,251.048
S1	52.0	3,909.978
L2	53.0	4,591.942
R2	52.0	5,118.036
S1.5	53.0	6,264.151
R2.5	53.0	8,498.373
O3	66.0	9,217.495
S2	53.0	9,450.341
L3	54.0	10,237.454
O4	86.0	12,365.760
R3	53.0	13,069.801
S3	54.0	16,607.378
L4	54.0	19,655.879
R4	54.0	22,386.099
S4	54.0	27,068.849
L5	55.0	30,183.631
R5	55.0	34,679.860
S5	55.0	37,757.281
S6	54.0	47,537.233
SQ	54.0	67,057.979

Analytical Parameters

OLT Placement Band:	1915 - 2006
OLT Experience Band:	1997 - 2006
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	92.0



Analytical Parameters

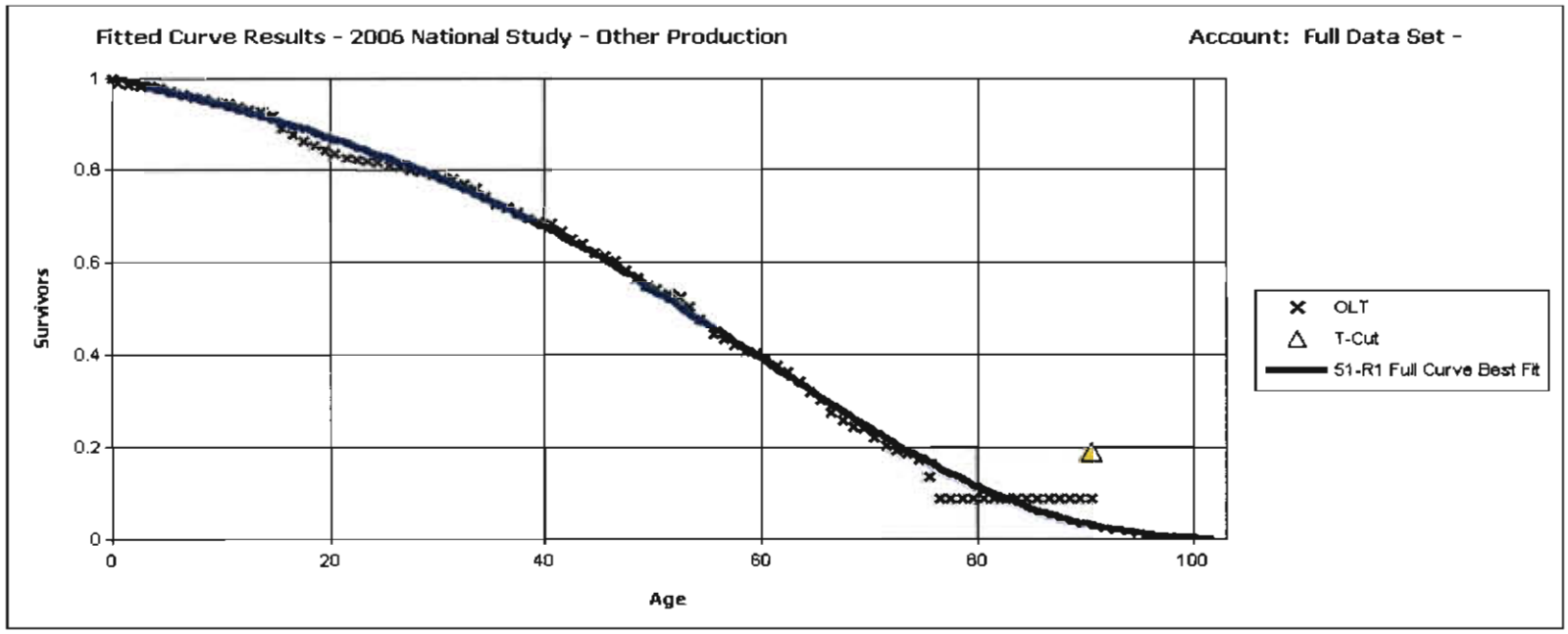
OLT Placement Band:	1915 - 2006
OLT Experience Band:	2002 - 2006
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	92.0

Best Fit Curve Results
2006 National Study - Other Production
Account: Full Data Set -

Curve	Life	Sum of Squared Differences
BAND	2002 - 2006	
L0	43.0	570.514
L0.5	44.0	733.272
O1	42.0	807.800
S-0.5	43.0	1,073.940
O2	44.0	1,097.520
R0.5	43.0	1,364.704
L1	44.0	1,625.260
S0	43.0	2,514.163
R1	43.0	3,486.196
L1.5	44.0	3,540.542
S0.5	44.0	4,562.316
O3	51.0	6,013.842
R1.5	44.0	6,246.758
L2	44.0	6,338.362
S1	44.0	7,371.521
O4	64.0	9,798.844
R2	44.0	10,081.373
S1.5	44.0	10,660.152
L3	44.0	14,297.055
R2.5	44.0	14,369.717
S2	44.0	14,687.789
R3	44.0	19,693.366
S3	44.0	23,107.335
L4	44.0	25,940.554
R4	44.0	29,708.113
S4	44.0	34,177.292
L5	44.0	37,025.036
R5	44.0	41,663.706
S5	44.0	44,516.800
S6	43.0	53,411.639
SQ	42.0	70,413.367

Analytical Parameters

OLT Placement Band:	1915 - 2006
OLT Experience Band:	2002 - 2006
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	92.0



Analytical Parameters

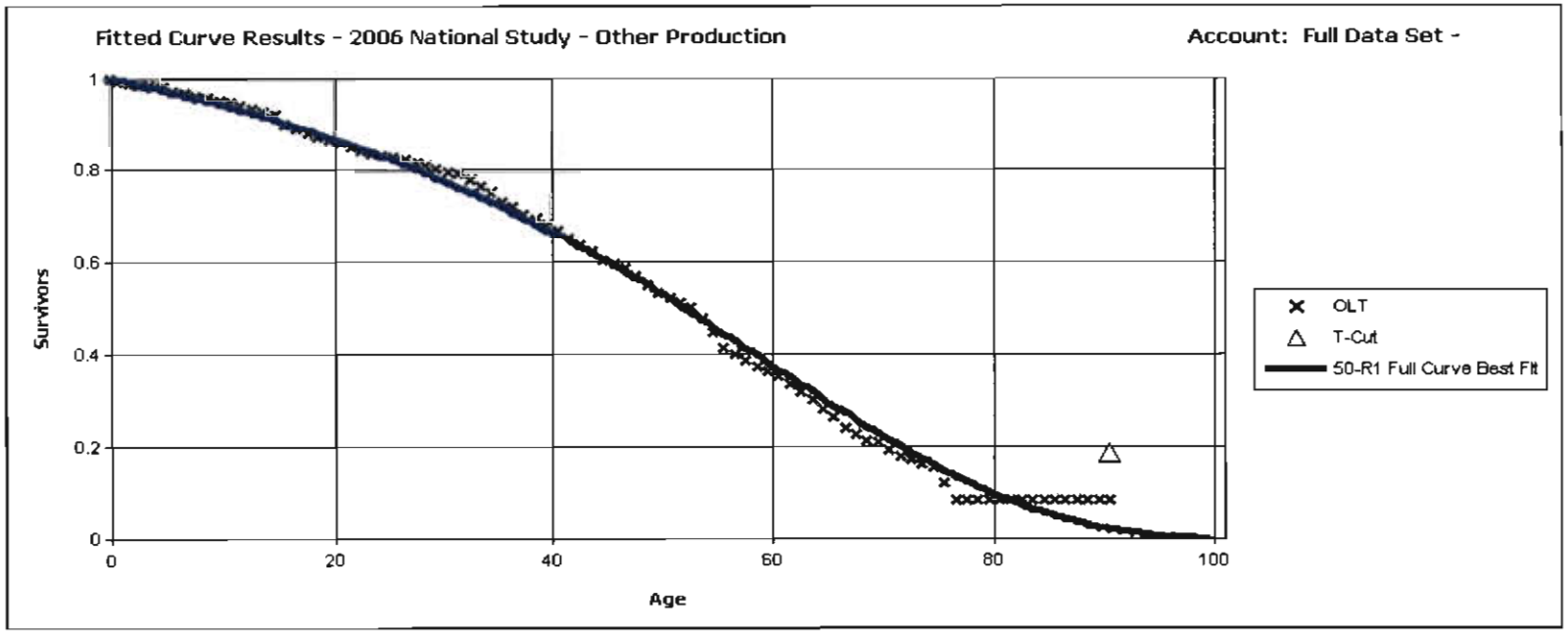
OLT Placement Band:	1915 - 2006
OLT Experience Band:	1992 - 2006
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	92.0

Best Fit Curve Results
2006 National Study - Other Production
Account: Full Data Set -

Curve	Life	Sum of Squared Differences
BAND	**1992 - 2006**	
R1	51.0	373.338
S0	51.0	803.503
R1.5	52.0	932.509
S0.5	52.0	942.953
R0.5	50.0	1,169.078
S-0.5	50.0	1,635.602
L1.5	53.0	1,855.708
L1	53.0	1,932.967
S1	52.0	1,935.752
R2	52.0	2,651.549
L0.5	53.0	2,670.279
L2	53.0	2,769.720
S1.5	53.0	3,472.572
O1	49.0	3,723.966
L0	53.0	4,176.289
R2.5	53.0	5,175.949
O2	54.0	5,258.105
S2	53.0	5,852.621
L3	54.0	6,508.614
R3	53.0	8,858.409
S3	54.0	11,661.901
O3	67.0	12,537.541
L4	54.0	14,245.641
O4	88.0	16,145.723
R4	54.0	16,861.330
S4	54.0	20,824.962
L5	54.0	23,662.298
R5	54.0	27,915.173
S5	54.0	30,717.660
S6	54.0	40,053.065
SQ	54.0	59,379.950

Analytical Parameters

OLT Placement Band:	1915 - 2006
OLT Experience Band:	1992 - 2006
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	92.0



Analytical Parameters

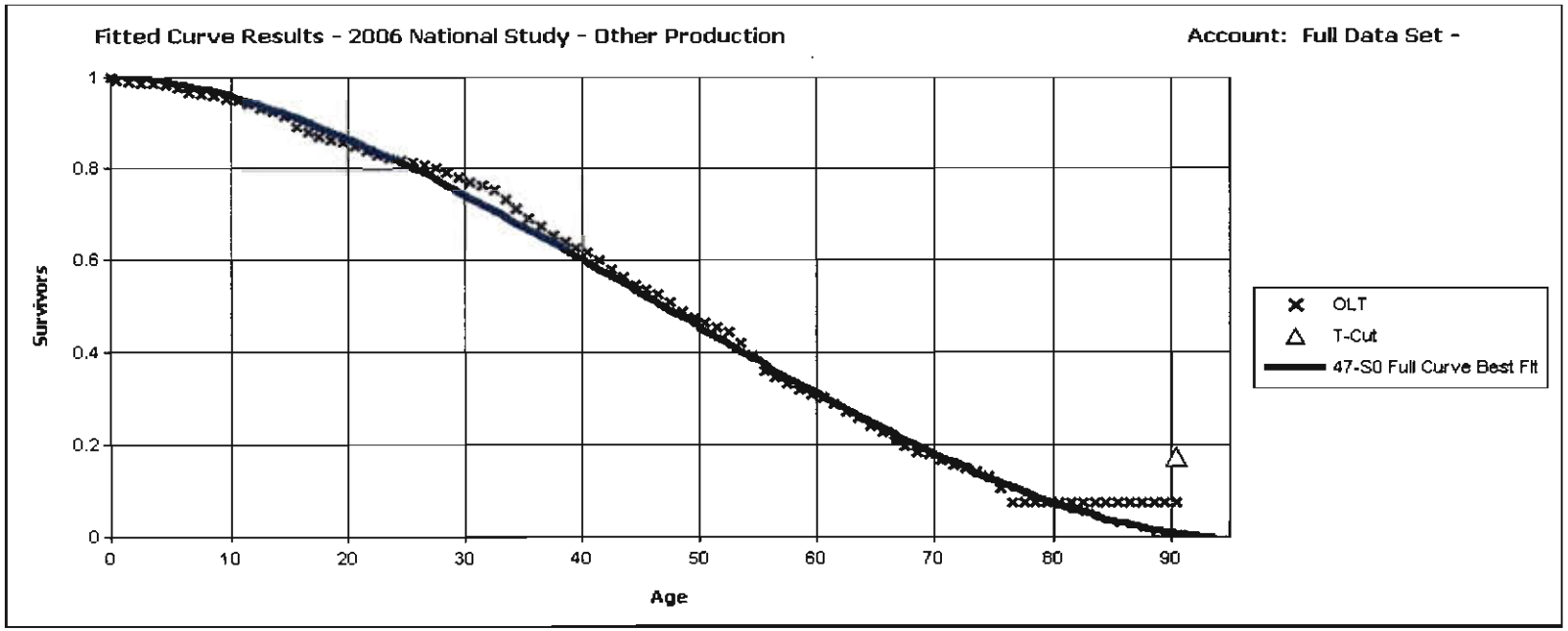
OLT Placement Band:	1915 - 2006
OLT Experience Band:	1987 - 2006
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	92.0

Best Fit Curve Results
2006 National Study - Other Production
Account: Full Data Set -

Curve	Life	Sum of Squared Differences
BAND	1987 - 2006	
R1	50.0	407.076
S0.5	51.0	561.418
R1.5	50.0	600.198
S0	50.0	729.878
S1	51.0	1,217.407
L1.5	52.0	1,275.730
R0.5	49.0	1,502.486
L2	52.0	1,767.225
L1	52.0	1,767.358
S-0.5	49.0	1,928.851
R2	51.0	1,997.721
S1.5	52.0	2,479.248
L0.5	52.0	2,833.270
R2.5	51.0	4,194.343
O1	48.0	4,384.240
S2	52.0	4,523.014
L0	52.0	4,666.417
L3	53.0	4,875.081
O2	53.0	6,004.430
R3	52.0	7,470.060
S3	52.0	9,843.788
L4	53.0	12,106.296
O3	65.0	13,988.226
R4	52.0	14,856.560
O4	85.0	17,978.888
S4	53.0	18,388.649
L5	53.0	20,995.287
R5	53.0	25,112.445
S5	53.0	27,742.382
S6	52.0	36,631.534
SQ	53.0	55,655.989

Analytical Parameters

OLT Placement Band:	1915 - 2006
OLT Experience Band:	1987 - 2006
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	92.0



Analytical Parameters

OLT Placement Band:	1915 - 2006
OLT Experience Band:	1982 - 2006
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	92.0

Best Fit Curve Results
2006 National Study - Other Production
Account: Full Data Set -

Curve	Life	Sum of Squared Differences
BAND	**1982 - 2006**	
S0	47.0	436.315
R1	47.0	447.815
S0.5	48.0	558.954
L1.5	49.0	811.212
R0.5	46.0	992.633
L1	49.0	995.881
R1.5	48.0	1,067.941
S-0.5	47.0	1,209.038
L2	49.0	1,579.596
S1	48.0	1,585.670
L0.5	49.0	1,839.119
R2	48.0	2,856.566
S1.5	49.0	3,105.025
O1	46.0	3,246.618
L0	49.0	3,444.781
O2	50.0	4,794.791
R2.5	49.0	5,346.921
L3	50.0	5,397.725
S2	49.0	5,442.534
R3	49.0	8,899.024
S3	49.0	11,185.926
O3	60.0	12,830.068
L4	50.0	13,448.811
R4	49.0	16,545.762
O4	78.0	17,201.400
S4	49.0	20,048.824
L5	49.0	22,634.242
R5	49.0	26,792.613
S5	49.0	29,391.583
S6	49.0	38,145.975
SQ	48.0	56,837.585

Analytical Parameters

OLT Placement Band:	1915 - 2006
OLT Experience Band:	1982 - 2006
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	92.0

Northern Indiana Public Service Company

April 2, 2009

Tour of Facilities

Northern Indiana Public Service Company
April 2, 2009
Tour of Facilities

Contents

I. **Report**

II. **Photographs**

Northern Indiana Public Service Company

April 2, 2009

Tour of Facilities

I. Report

Introduction. This report summarizes an April 2, 2009 plant tour of Northern Indiana Public Service Company's ("NIPSCO") Mitchell, Bailly, Michigan City and Schahfer generating stations. Mr. Michael J. Meyers – NIPSCO's Engineering Supervisor – Major Projects lead the tour. Ms. Cynthia Pruett, Ms. Jennifer Sumner, Ms. Margaret Kenney and Mr. Michael J. Majoros attended on behalf of the Indiana Office of Utility Consumer Counselor ("OUCC"). The OUCC's tour was actually an update of an August 23, 2001 OUCC plant tour taken in the context of the depreciation study it filed in Cause No. 41746.

Background. NIPSCO filed a Depreciation Study in Cause No. 41746 and the OUCC retained Snavely King to respond to NIPSCO's study. Snavely King, in turn, conducted a plant tour in the context of conducting its own independent depreciation study. The parties settled Cause No. 41746 with no change to the then present depreciation rates. In the current proceeding, NIPSCO filed a new depreciation study conducted by Mr. John Spanos. Mr. Spanos stated that "A field trip was conducted" and that "this knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses."[1] Consequently, the OUCC deemed it prudent to take another tour and update our previous findings. We viewed the operations of the plants and discussed routine and long-term maintenance practices. We discussed the types of maintenance upgrades and modernization projects typically conducted and planned to be conducted at each plant, and we specifically went through our prior report on a page-by-page, picture-by-picture basis.

Overall Conclusion. This report includes numerous photographs taken by Ms. Kenney during the course of the tour. The most startling aspect of the trip was that both the Mitchell and

[1] Exhibit JJS-2, page 28 of 522.

Michigan City plants were idle. Plant Mitchell was fenced-in and appeared to be decaying with no personnel other than three guards, on site. Michigan City was idle because its main conveyor was being repaired due to damage caused by a fire. Both of these plants were operational, in fact, in excellent condition during our prior tour. The Bailly and Schahfer plants were operating and appeared to be in good condition.

D. H. Mitchell Generating Station. (Photographs 1 - 13.) Mitchell is located on a 100-acre Lake Michigan site in Gary, Indiana. There are five units at the Mitchell Station. Units 4, 5 and 6 are 125 MW sister units built by Combustion Engineering. Unit 4 was installed in 1956 and Units 5 and 6 were installed in 1959. Unit 11 is a 110 MW cyclone boiler installed by B&W in 1970. Unit 9A is a 17.4 MW natural gas unit installed in 1970. It is rarely used.

Units 4, 5 and 6 can run on coal or natural gas. However, for environmental reasons, Units 4 and 5 cannot both run on coal at the same time. Units 4 and 5 share one stack while Units 6 and 11 share the other stack at Mitchell. Units 6 and 11 have low NOx burners. Unit 11 has digital controls. Mitchell uses the same type of "once-through" cooling system as the Bailly plant.

During our August 23, 2001 tour for Cause No. 41746, management considered the Mitchell units to be very reliable, and did not have any plans to retire any of these units. They intended to operate them as long as it was economical to do so. For example, in Cause No. 41746, Mr. Robinson proposed the following life spans and retirement years for the Mitchell units.

Robinson 2001 Life Spans

For Mitchell

Unit	In-Service	Retirement Year	Life Span
4	1956	2016	60
5	1959	2019	60
6	1959	2019	60
11	1970	2010	40

Consequently, we were surprised to read Mr. Spanos's, Mr. Pack's, and Mr. Sweet's declaration that NIPSCO had taken the Mitchell plant out of service. During our tour we confirmed that the plant was shut-down, and all coal had either been transferred to other plants

or burned down. We also note that during his tour, Mr. Spanos apparently climbed through the idle plant with a flashlight. We did not deem that necessary for our purposes.

Several idle and empty coal cars were at the site. The only personnel we observed were three guards, and the only other activity was a lit aircraft beacon. Electricity for the beacon is being drawn from the grid rather than from power generated at Mitchell. The guards and electricity constitute the only expenses associated with the Mitchell plant at this time. We learned that NIPSCO does not have any legal retirement to demolish the plant and will not demolish the plant unless Mr. Spanos' request for decommissioning funds is approved. In fact, we understand that the transmission substation at the plant will remain in place. Mr. Spanos's life span estimates are as follows:

Spanos 2007 Life Spans

For Mitchell

Unit	In-Service	Retirement Year	Life Span
4	1956	2007	51
5	1959	2007	48
6	1959	2007	49
11	1970	2007	37

Bailly Generating Station. (Photographs 14 - 39.) Bailly is located on a 100-acre site on the shore of Lake Michigan in Porter County, Indiana. There is a large empty field near the entrance to the Bailly station. This is the site of a previously planned nuclear plant that was abandoned circa 1981. There was a substantial amount of investment ($28 million) added to the Unit 8 Boiler Plant Equipment account in 1981. It is speculated that that money is the original nuclear plant investment.

There are three units at Bailly: Units 7, 8 and 10. Units 7 and 8 are 160 and 320 MW coal-fired cyclone boilers which commenced operations in 1962 and 1968 respectively. Unit 10 is a 31 MW gas turbine installed in 1968. Overall, Bailly appears to be a well maintained and well managed plant. The Company has no plans to retire any of the existing units at the plant.

Bailly Units 7 and 8

Units 7 and 8 are able to burn high-sulfur midwestern coal as a result of an on-site Flue Gas Desulfurization ("FGD") system owned and operated by PURE AIR. There is a common stack for both units. Bailly Units 7 and 8 have new electronic controls – data acquisition and control. New SCR's were installed for Units 7 and 8 subsequent to 2001. The Bailly plant uses a "once-through" cooling system. Water is drawn from Lake Michigan, cleared of debris and passed through the condenser and then back into Lake Michigan. Cooling towers are not used in this once-through process. Although the water is warm, creating some environmental concerns, it is cleaner when it flows back into Lake Michigan than when it was drawn.

The shoreline appears to be presenting a major problem at Bailly. Sand which has been deposited at the front of the plant along the shoreline is building up and has pushed the lake back towards the intake structures, thus presenting problems getting cooling water into the plant. This is apparently a job for the Army Corps of Engineers, given that this is a national lake shore.

The equipment in the coal yard has been upgraded in past several years. The "stacker outer" enables quicker coal handling. Although not new, "The Joey" (nee "The Barney)" car haul positioning device, which is operated by cables, combined with the train track ramp is unique and provides a significant component of the fully automated coal handling function. The Joey/Barney positions coal cars in the rotary dumber. Decoupled cars flow to the "kick-back" ramp which slows them and then enables them to switch tracks on the way back.

Bailly Unit 10

[redacted]

Spanos 2007 Life Spans

For Bailly

Unit	In-Service	Retirement Year	Life Span
7	1962	2023	61
8	1968	2028	60
10	1968	2019	51

Michigan City Station. (Photographs 40 - 57.)

Michigan City is located on a 131-acre site on Lake Michigan and is the home to the first electric generating station built by NIPSCO in 1929. The plant is unique in appearance due to its hyperbolic cooling tower usually associated with nuclear plants. We noted that most of the cooling in the tower takes place at the bottom. The Michigan City plant appears very well maintained and there are no plans for its retirement.

Ordinarily, generating plant units refer to boilers; however, at Michigan City, the term "unit" refers to generators. Unit 1 began operation in 1931. Three boilers supplied steam to this 68 MW turbine-generator. The boilers were fired by coal until 1968 when they were converted to natural gas. Unit 1 and its three boilers were retired in 1978 and "scrapped-out."

Construction on Units 2 and 3 began in 1949. These two 70 MW turbine-generators are located in the "old side" of the building that houses the boilers and generators. They were installed in 1950 and 1951, and were originally supplied by three coal-fired cyclone boilers. The cyclone furnaces were abandoned in-place. On June 1, 1988 these boilers were also converted to burn natural gas. At the time of our August 23, 2001 tour, Units 2 and 3 were being used occasionally for "peaking" operations. Units 2 and 3 were only used one time during summer 2001 and are no longer used at all. Although NIPSCO's depreciation study assumes these units will be demolished, we understand that they will only be demolished if the IURC approves additional charges to ratepayers to pay for the demolition. NIPSCO does not have any legal obligation to demolish the units.

Unit 12 is a 500 MW turbine-generator supplied by a 540 MW (nameplate) cyclone boiler. It commenced operation in 1974. Unit 12 has undergone numerous upgrades since initially installed. Much of the old coal handling equipment has been abandoned. The remaining equipment feeds Unit 12 with Powder River Basin ("PRB") coal. The 1992 conversion to PRB

coal was substantial from a cost standpoint. At the time of our August 23, 2001 tour, the Company had also installed new dust collection equipment. Additionally, an Overfire Air duct work system was installed, reducing NOx emissions by 50 percent. The control room had been upgraded for both data acquisition and control. Subsequent to our 2001 tour, NIPSCO installed new SCRs and upgrades to the fans on the Unit 12 boiler.

Unit 12 was idle during our April 2, 2009 tour. The main coal supply conveyor had been destroyed in a fire and was being repaired. Given this downtime, NIPSCO apparently accelerated a scheduled fall maintenance outage to take advantage of the situation. We did not, however, observe any boiler or turbine maintenance work taking place during our tour.

Spanos 2007 Life Span

For Michigan City

Unit	In-Service	Retirement Year	Life Span
12	1974	2034	60

R.M. Schahfer Station. (Photographs 58 - 99.) The Schahfer station is two miles south of the Kankakee River in Jasper County, Indiana. It is the largest of NIPSCO's four generating stations. Schahfer is the "flagship of the fleet." The plant appears very well maintained and there are no retirement plans.

Schahfer Station consists of four coal-fired units (Nos. 14, 15, 17 and 18) and two gas-fired units (16A and 16B). Unit 14, installed in 1976, is a 431 MW cyclone boiler built by Babcock & Wilcox, while Unit 15, installed in 1979, is a 472 MW boiler built by Foster & Wheeler. Both units were upgraded to burn low-sulfur PRB coal in 1994. Units 17 and 18 are 361 MW coal units built in 1983 and 1986 respectively by Combustion Engineering. These units burn midwestern high sulfur coal blended with petroleum coke. All units are outfitted with a FGD process.

The FGD process was upgraded in 1996. The 1996 upgrade consisted of converting from dual alkalai to a limestone forced oxidation process. This new process yields synthetic gypsum, instead of landfilled on-site waste. Wallboard quality gypsum is a by-product of the FGD system. Georgia Pacific built a $70 million wallboard plant next to the Schahfer station in order to purchase and utilize the gypsum byproduct. NIPSCO receives a cash return from this by-product. The FGD process was upgraded further subsequent to our August 23, 2001 tour.

The control panels for all units have been upgraded to provide for electronic data gathering, control and modeling from the upgraded hardware and software. New low NOx burners have been installed on Unit 15. Also, the Company installed new coal hopper barrel chargers at Units 14 and 15. A new SCR has been installed on Unit 14. Additional major expenditures at Units 14 and 15 have included a 1990 cold-hot side conversion (duct work etc), gas recirculation work, turbine overhauls, etc. Upgrades have also included the 1994 conversion to PRB coal, fuel handling, dust collectors, modifications to absorption elements and primary superheater work.

Spanos 2007 Life Spans

For Schahfer

Unit	In-Service	Retirement Year	Life Span
14	1976	2036	60
15	1979	2039	60
17	1983	2043	60
18	1986	2046	60
16A	1979	2020	41
16B	1979	2020	41

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4 - Unit 9A – Idle.
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4 – Unit 9A – Idle.

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5 – Transmission substation for incoming power.

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8 – Conveyor – Idle.

D. H. Mitchell Station

9 – Idle coal handling equipment.

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48 – Bottom of cooling tower.

49 – Site of retired units.

50 – Space formerly occupied by Unit 1.

51 – Units 2 and 3.

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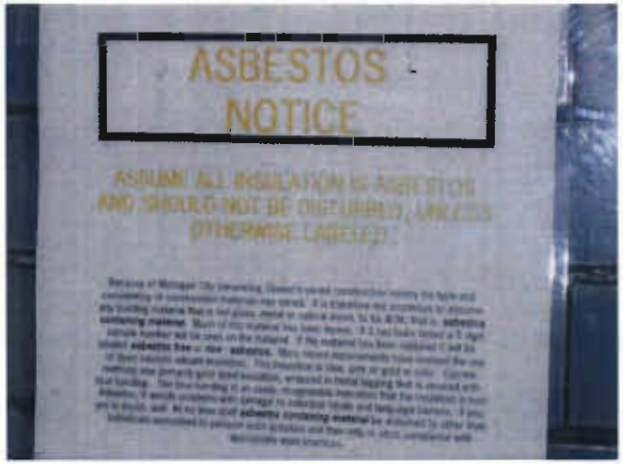
52 – Old side.

53 – Old side crane.



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83 – View from roof showing coal conveyor to plant, fly ash silos and ESPs.

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99 – Grinding component for coal pulverizer.

~~Exhibit___(MJM-2)~~

Northern Indiana Public Service Company

August 23, 2001

Tour of Facilities

Northern Indiana Public Service Company
August 23, 2001
Tour of Facilities

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Northern Indiana Public Service Company

August 23, 2001

Tour of Facilities

I. Report

Introduction. This report summarizes an August 23, 2001 plant tour of Northern Indiana Public Service Company's ("NIPSCO") Schahfer, Michigan City, Bailly and Mitchell generating stations. The tour was led by Mr. Jerry Weeden – NIPSCO's Executive Director, Electric Production. Mr. Timothy Geswein and Mr. Michael J. Majoros attended on behalf of the Indiana Office of Utility Consumer Counselor ("OUCC").

Background. NIPSCO filed a Depreciation Study prepared by Mr. Earl Robinson which will, if accepted, substantially increase depreciation rates and expenses to be charged to its customers. About one-half of the increase is in the Steam Production Plant function.

Mr. Robinson stated that he "performed a physical plant inspection of a representative portion of the Company's operating facilities," and that he "met with management representatives, as well as held telephone conference calls with ...various Company personnel to discuss factors anticipated to impact each of the Company's property groups."[1] One objective of the tour, therefore, was to obtain a similar level of knowledge and understanding as Mr. Robinson.

Mr. Robinson is proposing the "life span" method to compute production plant depreciation rates. In conjunction with this method, Mr. Robinson estimated "probable" or final retirement years for each unit of each facility. Generally, these probable retirement years and the resulting remaining life spans appear to have been taken from the Company's Integrated Resource Plan ("IRP"). However, Mr. Robinson independently shortened several of the remaining life spans based on his own judgment.

[1] Direct Testimony of Earl M. Robinson, Respondent's Exhibit EMR-1 ("Robinson testimony"), page 7.

The NARUC 1996 Depreciation Practices Manual specifies that the estimated probable retirement year is "the most important factor in the depreciation rate for life span properties." [2] Consequently, another objective of the tour was to determine if there were any visual signs which would provide information concerning a specific probable retirement year, or if plant management personnel could provide any additional information relating to Mr. Robinson's probable retirement year estimates.

Finally, Mr. Geswein and Mr. Majoros viewed the operations of the plants and discussed routine and long-term maintenance practices. They discussed the types of maintenance upgrades and modernization projects typically conducted and planned to be conducted at each plant.

Overall Conclusion. This report includes numerous photographs taken by Mr. Majoros during the course of the tour. In general these plants appear to be very well managed and maintained. Steps have been taken to properly maintain and modernize the plants, to improve the efficiency and operations at the plants, and to meet environmental concerns. None of the plant management personnel with whom discussions were held were aware of any plans to retire any of the plants or units. In fact, these personnel took great pride in their plants. Consequently, the plant tour and conversations with plant management personnel do not support Mr. Robinson's probable retirement years, particularly those which he judgmentally reduced.

Tour. (Photographs 1-2.) The tour began at 8:00 a.m., August 23, 2001, at NIPSCO's Corporate Headquarters in Merrillville, Indiana. Mr. Geswein and Mr. Majoros were met by Jennifer Smith and introduced to Mr. Weeden who led the tour. Mr. Weeden asked Mr. Majoros to obtain approval for any pictures to be taken. He also requested that no Company employees be photographed and that the tour not be videotaped. The first site on the tour was the Schahfer generating station.

NW Schf Tour

R.M. Schahfer Station. (Photographs 3-13.) The Schahfer station is two miles south of the Kankakee River in Jasper County, IN. It is the largest of NIPSCO's four generating stations.

2 Public Utility Depreciation Practices, National Association of Public Utility Commissioners ("NARUC"), August 1996, p. 146

Mr. M. Canner and Mr. D.E. Fitzgerald (the plant operations management team) met the participants. Mr. Fitzgerald led the tour of the plant.

Schahfer Station consists of four coal-fired units (Nos. 14, 15, 17 and 18) and two gas-fired units (16A and 16B). Unit 14, installed in 1976, is a 431 MW cyclone boiler built by Babcock & Wilcox, while Unit 15, installed in 1979, is a 472 MW boiler built by Foster & Wheeler. Both units were upgraded to burn low-sulfur Powder River Basin ("PRB") coal in 1994. Units 17 and 18 are 361 MW coal units built in 1983 and 1986 respectively by Combustion Engineering. These units burn midwestern high sulfur coal blended with petroleum coke using a flue gas de-sulfurization ("FGD") process.

The FGD process was upgraded in 1996. The 1996 upgrade consisted of converting from dual alkalai to a limestone forced oxidation process. This new process yields synthetic gypsum, instead of landfilled on-site waste. Wallboard quality gypsum is a by-product of the FGD system. Georgia Pacific built a $70 million wallboard plant next to the Schahfer station in order to purchase and utilize the gypsum byproduct. NIPSCO receives a cash return from this by-product.

The control panels for Units 14 and 15 have been upgraded to provide for electronic data gathering. This is phase one of a two-phase upgrade. Phase two enables control and modeling from the upgraded hardware and software. Unit 14 has also been upgraded for controls. The Unit 17 control panel is scheduled to be upgraded for data acquisition and controls this fall. Unit 18's controls will be upgraded some time in the future.

A Unit 15 reheater replacement is scheduled for next year. Also, the Company plans to install new barrel chargers at Units 14 and 15. Additionally, major expenditures have already been made at Units 14 and 15. In 1990 there was a cold-hot side conversion (duct work etc). There has also been gas recirculation work, turbine overhauls, etc. Upgrades have also included the 1994 conversion to PRB coal, fuel handling, dust collectors, modifications to absorption elements and primary superheater work.

Mr. Robinson shortened the probable retirement years for all of the coal-fired units at the Schahfer plant. Schahfer plant management, however, considers it to be the "flagship of the fleet." The plant appears very well maintained and there are no retirement plans. Mr.

Robinson's shortened lives appear to be arbitrary and in conflict with reality. Even the IRP lives are probably understated.

Michigan City Station. (Photographs 14-27.) Larry Nemcek and Jerry Smoltz (Michigan City operations management team) met the participants. Mr. Nemcek provided an overview of the plant boilers and plant operations. Mr. Smoltz led the tour through the plant.

Michigan City is located on a 131-acre site on Lake Michigan and is the home to the first electric generating station built by NIPSCO in 1929. Ordinarily, generating plant units refer to boilers; however, at Michigan City, the term "unit" refers to generators. Unit 1 began operation in 1931. Three boilers supplied steam to this 68 MW turbine-generator. The boilers were fired by coal until 1968 when they were converted to natural gas. Unit 1 and its three boilers were retired in 1978 and "scrapped-out."

Construction on Units 2 and 3 began in 1949. These two 70 MW turbine-generators were installed in 1950 and 1951. They were originally supplied by three coal-fired cyclone boilers. On June 1, 1988 these boilers were also converted to burn natural gas. The cyclone furnaces appear to have been abandoned in-place. Units 2 and 3 are now used for "peaking" operations and are rarely used. Units 2 and 3 were only used one time this summer. Peaking units do not receive the same maintenance and scrutiny as the larger base-load units.

Unit 12 is a 500 MW turbine-generator supplied by a 540 MW (nameplate) cyclone boiler. It commenced operation in 1974. Mr. Robinson reduced the IRP retirement date of this unit by 20 years, from 2034 to 2014. Unit 12 has undergone numerous upgrades since initially installed. Much of the old coal handling equipment has been abandoned. The remaining equipment feeds Unit 12 with PRB coal. The 1992 conversion to PRB coal was substantial from a cost standpoint. The Company has also installed new dust collection equipment. Additionally, an Overfire Air duct work system was installed, reducing NOx emissions by 50 percent. The control room has been upgraded for both data acquisition and control. New SCR #12 installed since this tour

The Michigan City plant appears very well maintained and there are no plans for its retirement. Mr. Robinson's 20 year reduction to Unit 12's life is neither supported by the facts nor by observation.

Bailly Generating Station. (Photographs 28-48.) Bailly is located on a 100-acre site on the shore of Lake Michigan in Porter County, IN. Phil Pack, Plant Operations Manager, led the tour through Bailly. The station was undergoing an internal safety and environmental audit at the time of the tour.

There are three units at Bailly: Units 7, 8 and 10. Mr. Robinson reduced the IRP life spans by 1 year for Unit 7 and by 7 years for Unit 8. Units 7 and 8 are 160 and 320 MW cyclone boilers which commenced operations in 1962 and 1968 respectively. There is a common stack for both units. Unit 10 is a 31 MW gas turbine installed in 1968.

Units 7 and 8 are able to burn high-sulfur midwestern coal as a result of an on-site FGD system owned and operated by PURE AIR. Bailly Unit 8 has new electronic controls – data acquisition and control - whereas Unit 7 has data acquisition only. Eventually all controls will be upgraded. – that they has been upgraded

The equipment in the coal yard has been upgraded in past years. The new "stacker outer" enables quicker coal handling. Although not new, "The Barney" train track ramp is unique. The ramp is used to slow empty decoupled coal cars on the way up and then enables them to switch tracks on the way back down.

The Bailly plant uses a "once-through" cooling system. Water is drawn from Lake Michigan, cleared of debris and passed through the condenser, and then back into Lake Michigan. Cooling towers are not used in this once-through process. Although the water is warm, creating some environmental concerns, it is cleaner when it flows back into Lake Michigan than when it was drawn.

There is a large empty field near the entrance to the Bailly station. This is the site of a previously planned nuclear plant that was abandoned circa 1981. There was a substantial amount of investment ($28 million) added to the Unit 8 Boiler Plant Equipment account in 1981. It is speculated that that money is the original nuclear plant investment.

Bailly appears to be a well maintained and well managed plant. The Company has no plans to retire either Unit 7 or Unit 8. Mr. Robinson's retirement year reductions are unwarranted.

New SCR's subsequent to the tour

D. H. Mitchell Generating Station. (Photographs 49-66.) Mitchell is located on a 100-acre Lake Michigan site in Gary, Indiana. Gene Fox and Mike McBride met the tour and described the overall operations. Mike McBride then led the rest of the tour. There are five units at the Mitchell Station. Units 4, 5 and 6 are 125 MW sister units built by Combustion Engineering. Unit 4 was installed in 1956 and Units 5 and 6 were installed in 1959. Unit 11 is a 110 MW cyclone boiler installed by B&W in 1970. Unit 9A is a 17.4 MW natural gas unit installed in 1970. It is rarely used.

Units 4, 5 and 6 can run on coal or natural gas. However, for environmental reasons, Units 4 and 5 cannot both run on coal at the same time. Units 4 and 5 share one stack while Units 6 and 11 share the other stack at Mitchell. Units 6 and 11 have low NOx burners. Unit 11 has digital controls. Mitchell uses the same type of "once-through" cooling system that was described in the Bailly discussion. Management considers the Mitchell units to be very reliable.

Mr. Robinson proposes the following life spans and retirement years for the Mitchell units.

Robinson Life Spans
For Mitchell

Unit	In-Service	Retirement Year	Life Span
4	1956	2016	60
5	1959	2019	60
6	1959	2019	60
11	1970	2010	40

NIPSCO's plant management does not have any plans to retire any of these units. They intend to operate them as long as it is economical to do so. None of the managers with whom the units were discussed could provide any rationale for assuming Unit 11 would only have a 40 year life or why it would be retired 9 years before the older Units 4, 5 and 6. Mr. Robinson's life span reduction for Unit 11 is not supportable.

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MERRILLVILLE, IN.

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2 - Tim Geswein in the lobby of Corporate Headquarters

R. M. SCHAHFER STATION

3 - Tim Geswein identifies the 556 MW turbine for Unit 15. The boiler was built by Foster - Wheeler in 1979 and is fueled by pulverized coal.

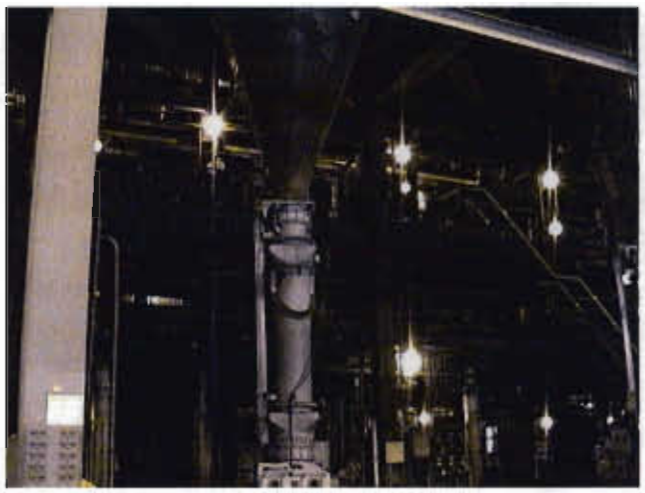
4 - Upgraded Control Room for Units 14 and 15.

5 - Data Acquisition System for Unit 15.

6 - This "breeching" between the two precipitators was installed when the units converted to Powder River Basin (PRB) low-sulfur coal.

R. M. SCHAHFER STATION

7 - Unit 18 Turbine. Units 17 and 18 are identical 423 MW steam turbines. The boilers were built by Combustion Engineering in 1983 and 1986.



8 - Unit 17 Coal chute and feeder. Units 17 and 18 have scrubbers and were upgraded with a flue gas desulfurization process.

9 - Control room for Units 17 and 18. Unit 17 control panels are scheduled to be upgraded this fall.

10 - Coal-handling system. Approximately 150 railroad cars of coal are burned daily.

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R. M. SCHAHFER STATION

11 - The cooling towers.

12 - $70 million Georgia Pacific wallboard plant uses gypsum byproduct from Schahfer flue gas desulfurization process to manufacture wallboard. NIPSCO gets a cash return on the byproduct.

Wasn't words for the Pulter
This the ~~plat form~~
the coal burning
Power Plant

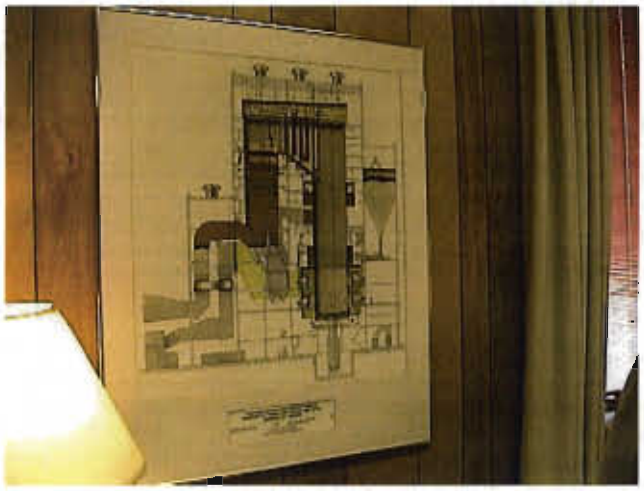
13 - The pollution controls begin with the electrostatic precipitator at the far right. The dirty flue gases then pass through the breeching enroute to the scrubbers, and then out the stack.

MICHIGAN CITY STATION

14 - A view of the hyperbolic cooling tower on the way to the plant.

15 - The auxiliary pollution control dust collection is provided by this bag-house.

16 - The stacks at Michigan City.



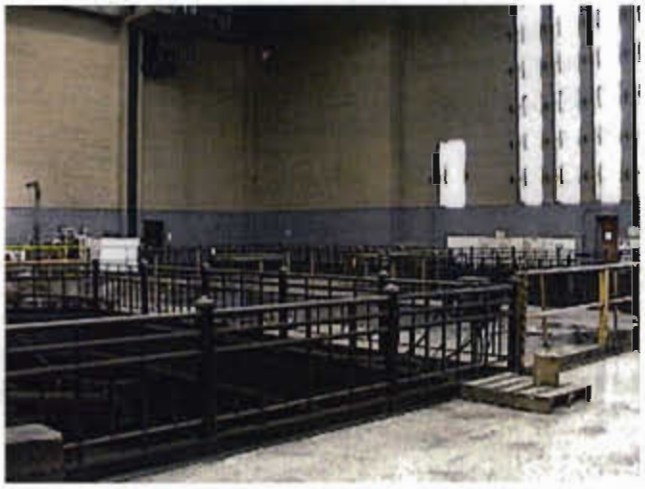
17 - Cross-sectional drawing of Unit 1.

MICHIGAN CITY STATION

18 - This aerial photograph is on display at the plant.

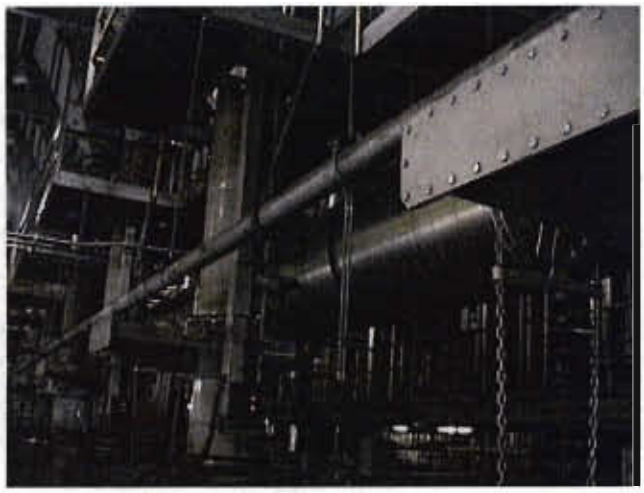
19 - Units 2 & 3 Steam Turbines (70 MW each).

20 - Graphic depiction of the overfire air project.



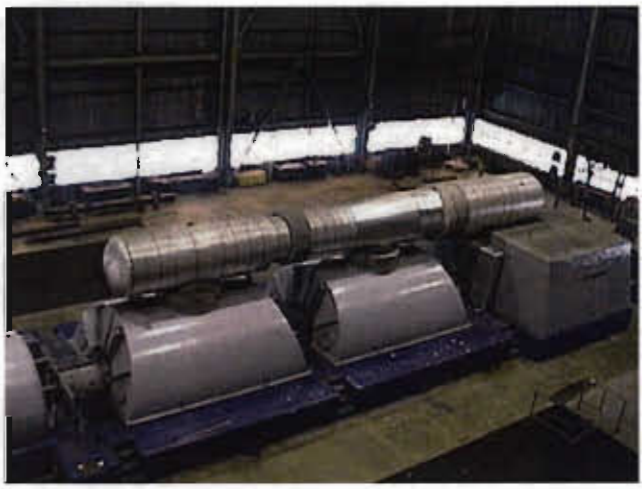
21 - Space formerly occupied by Unit 1.

MICHIGAN CITY STATION



22 - Overfire Air Duct system for Unit 12.

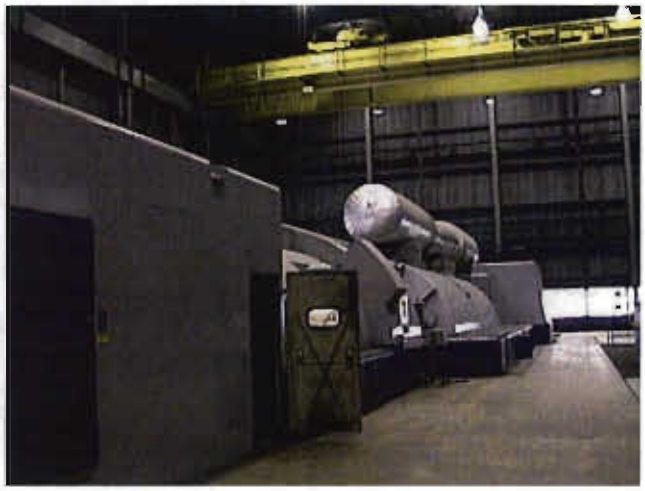
23 - These coal crushers feed *crushed* coal to the 570 MW Babcock & Wilcox cyclone boiler (Unit 12).



24 - Unit 12's 540 MW steam turbine was placed in service in 1974.

25 - Unit 12 Cyclone Furnace Feeder.

MICHIGAN CITY STATION



26 - Unit 12 Turbine.

27 - Control room at Michigan City.

BAILLY STATION

28 - Bailly Generating Plant in Porter County.

29 - Field where a nuclear plant was originally planned to be built.

30 - "The Barney". A train track resembling an amusement park ride. It's used to slow empty coal cars on the way up and then switch tracks on the way down.

31 - The coal conveyer (top of picture) and the pollution control system (center).

BAILLY STATION

32 - The breeching (term used to describe the "dirty" gas ductwork) from boiler plant on right to Pure Air facility on left. Pure Air provides flue gas desulfurization of emissions on a contract basis.

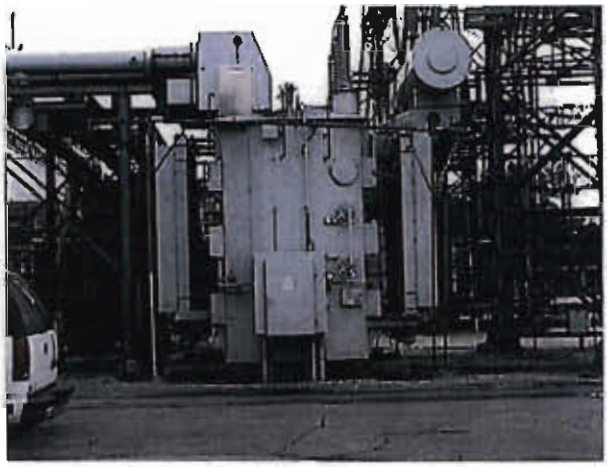
33 - The coal handling system and the coal yard.

34 - The downspill was upgraded last year to provide faster handling of the coal.

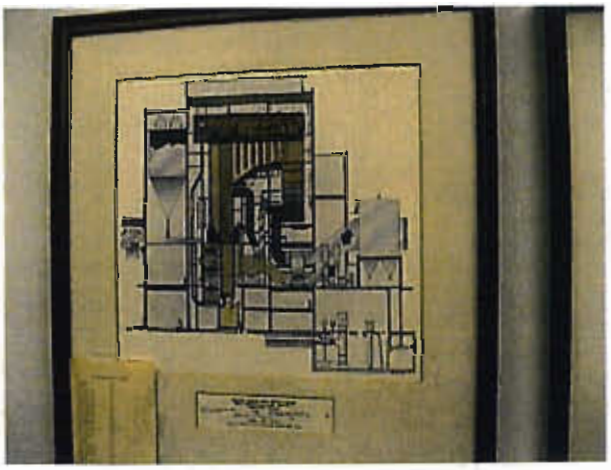
35 - The old "step up" transformer is being reconditioned.

Exhibit___(MJM-2)

BAILLY STATION

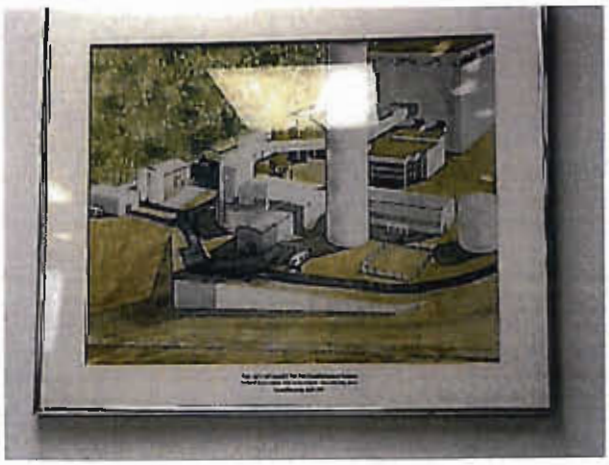


36 - The new "step up" transformer.



37 - Cross sectional drawing of Unit 7.

38 - Cross sectional drawing of Unit.



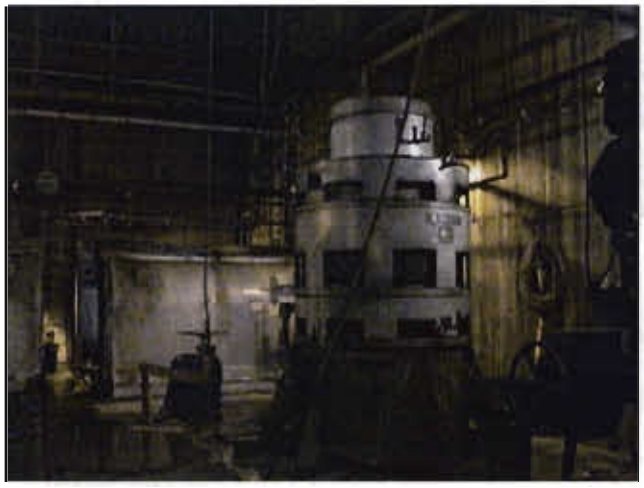
39 - Artist conception of the plant.

Focus on FGD facility

BAILLY STATION

40 - Unit 8 Turbine.

41 - The boiler feed pump.



42 - Water treatment system (intake from Lake Michigan).

43 - At the condenser intake, this traveling screen removes debris from water.

BAILLY STATION

44 - Boiler feed pump.

45 - The "Over Fire Air" feed duct.

46 - Coal feeder system from the hoppers to the coal crusher/feeder to the cyclone burners.

47 - This coal conveyer feeds coal from the coal yard to the boilers and to the coal *crusher*.

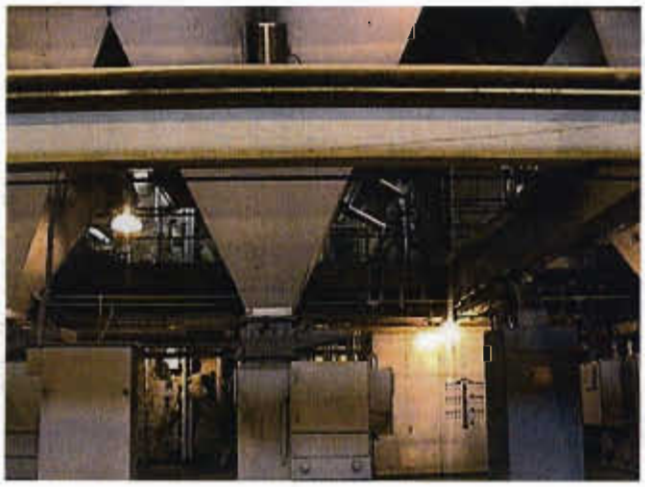
BAILLY STATION

48 - Control Room for Units 7 & 8. Unit 8 controls upgraded DACs and controls, Unit 7 DACs only.

D. H. MITCHELL STATION

49 - The four Units at Dean H. Mitchell (Lake).

50 - This cross sectional drawing of identical 138 MW Units 4, 5 & 6 hangs on the control room wall.



51 - Coal hoppers.

52 - The three 138 MW Steam Turbines.

D. H. MITCHELL STATION

53 - The control room that services all four coal units.

54 - The old control panel.

55 - Unit 11 controls have been upgraded to collect data as well as control the units.

56 - Cyclone Burner.

D. H. MITCHELL STATION

57 - Unit 9A, a 17.4 MW gas turbine that is rarely used.

58 - The ash silo.

59 - The coal handling system.

60 - A peek inside the firebox at Unit 5.

D. H. MITCHELL STATION

61 - Part of the coal pulverizer.

62 - The pulverizers.

63 - The Stacks and the Ash silo. Stack with nozzle to control height of plume shared by Units 6 and 11. Stack without nozzle shared by Units 4 and 5.

64 - This estuary feeds the condenser's intake.

Exhibit___(MJM-2)

D. H. MITCHELL STATION

65 - ~~The "clean" air goes up the stacks~~. The "dirty" flue gas passes through the electrostatic precipitators and the "fly-ash" is collected in the silo in the center of the photo.

66 - Water flows into the condenser on the left, and back into Lake Michigan on the right.

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OUCC Request 8 DEP-070

For all accounts and locations for which the life span method is proposed, please, provide the following information to support the final retirement dates. Please respond to each item.

a. Economic studies. (NARUC Deprecation Manual, p. 146)
b. Retirement plans. (NARUC, p. 146)
c. Forecasts. (NARUC, p. 146)
d. Studies of technological obsolescence. (NARUC, p. 146)
e. Studies of adequacy of capacity. (NARUC, p. 146)
f. Studies of competitive pressure. (NARUC, p. 146)
g. Relationship of type of construction to remaining life span.
h. Relationship of attained age to remaining life span.
i. Relationship of observed features and conditions at the time of field visits to remaining life span.
j. Relationship of specific plans of management to remaining life span.

Objections:

Response:

The life span method is proposed for Production Accounts 311 through 346 for NIPSCO. NIPSCO conducts periodic resource and economic analysis to determine probable retirement dates for each of the production units. One of the purposes of the resource plan is to recommend the capital improvements necessary to enable NIPSCO to continue to provide quality service that meets the needs of its customers. The resource plan examines adequacy of growth, assesses production capacity and unit efficiency.

As part of the operational planning process, NIPSCO assesses the adequacy of existing, major facilities and the need to make capital improvements, including complete replacement of such facilities during the time horizon studied. In so doing, various factors are considered, including engineering criteria, quality of service, evolving regulatory standards, environmental regulation and cost. This process forms the basis for the Company's development of detailed capital budgets and financing plans which, in turn, drive the specific capital projects that are completed each year. While this operational planning process does not result in detailed retirement plans beyond a 5-year horizon, it does project retirement dates for all major facilities of the company, and it provides

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analyses of both the service adequacy of existing major facilities during the study period and the major facility retirements, new construction and improvements recommended for the study period. If the Company determines that major facilities may cease to provide adequate service during the study period, retirement plans are determined. All major facilities continue to be assessed through the Company's year-to-year operational analysis and planning.

This operational planning process is established by the Company engineering department and supported by Gannett Fleming through site visits and the life span dates of other comparable facilities in the electric industry.

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OUCC Request 7-DEP-7:
Please provide copies of all external correspondence from 2006-2008, inclusive, including correspondence with Mr. Spanos and/or Gannett Fleming., which address in any way NIPSCO's retirement unit costs, electric depreciation rates, and/or the Depreciation Study.
Objections:
NIPSCO objects to Request 7-DEP-007 to the extent it refers to "retirement unit costs" on the grounds that it is vague and ambiguous and NIPSCO cannot reasonably determine what documents are within the scope of the Request. NIPSCO also objects to Request 7-DEP-007 to the extent it refers to "depreciation rates" on the grounds that it is unreasonably burdensome. NIPSCO further objects to Request 7-007 to the extent it seeks information that is protected by the attorney-client privilege or the work product privilege.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: The hard copy pages provided separately set forth external correspondence from 2006-2008 between Gannett Fleming and NIPSCO related to retirement unit costs, electric depreciation rates and/or the Depreciation Study. In addition, please see files attached hereto as OUCC Set 7-DEP-007 Attachment A through Attachment I.

"Spanos, John J."
<jspanos@GFNET.com>
06/24/2008 01:26 PM

To "Spanos, John J." <jspanos@GFNET.com>, <GLVajda@NiSource.com>
cc <jjleslie@NiSource.com>, <wmomalley@nisource.com>
bcc
Subject RE: [Possible Spam]RE: Seven Factor Transfers and To Be Detailed Estimates

Attached is my most up to date schedule of the results which utilize ELG and the most recent information from Burns & McDonnell. Their scrap value seems high in this version.

-----Original Message-----
From: Spanos, John J.
Sent: Tuesday, June 24, 2008 10:43 AM
To: 'GLVajda@NiSource.com'
Cc: jjleslie@NiSource.com; wmomalley@nisource.com
Subject: RE: [Possible Spam]RE: Seven Factor Transfers and To Be Detailed Estimates

Gay:

It is not appropriate to apply the electric file percentages to Sugar Creek. There are too many variables that are not related.

Also, I am sending you a schedule that sets forth the ELG rates. You can see there is a big jump in the rates when we calculated using the ELG prooedure. This schedule is PRELIMINARY as we have not incorporated the information from the most recent changes to the Burns and MCdonnel studies. We hope to be done with that late today or tomorrow morning.

John

-----Original Message-----
From: GLVajda@NiSource.com [mailto:GLVajda@NiSource.com]
Sent: Friday, June 20, 2008 11:45 AM
To: Spanos, John J.
Cc: jjleslie@NiSource.com; wmomalley@nisource.com
Subject: [Possible Spam]RE: Seven Factor Transfers and To Be Detailed Estimates

John,

Should we use apply the account percentages on the Electric file to CCGT facility?

Thank-you

Gay L. Vajda
Northern Indiana Public Service Company
Regulatory Accounting, Revenue Requirement
Phone 219-647-5694
Fax 219-647-4805
glvajda@nisource.com

NIPSCOe07ELG v6.xls

Gay Vajda/NCS/Enterprise
07/17/2008 08:46 PM

To jspanos@GFNET.com, mhoward@gfnet.com
cc Linda Miller/NCS/Enterprise@NiSource, William M O'Malley/NCS/Enterprise@NiSource, cherbst@huronconsultinggroup.com, Amy A
bcc
Subject Deprecation Study

Attach File -2

John and Melissa,

We have a couple of questions concerning the deprecation study. When we apply the composite rates to the FERC accounts, for example (Account 311.00 x 1.31) our total depreciation expense is approximately $5 million lower than your total of $160,873,834. If we add back DHMitchell and Unit 2 & 3 balances to the account totals our difference is approximately $36,000. Should the composite rate by account be adjusted so that when the account balances, excluding DHMitchell, result in an annual depreciation amount of $160,873,834? Our total for "Original Cost at December 31, 2007" ties to your total, which include DHMitchell and Units 2 &3.

The other question is in the 6/13 preliminary file, see attached, *NIPSCO-electric2007-ASL - withadjustments.xls*, several accounts are highlighted i.e. gas turbines and hydro's and then in the 6/30 file, *NIPSCOe07ELG.v6b.xls*, these same accounts have been moved. The total's on the two studies are within $700.00. Can you explain why these accounts have be moved? The FERC balances tie to the 6/13 study.

If you have any questions, do not hesitate to call me.

Thank-you for your support.

NIPSCOe07ELG v6b.xls NIPSCO-electric2007-ASL - withadjustments.xls

Gay L. Vajda
Cell 219-765-6301
Northern Indiana Public Service Company
Regulatory Accounting, Revenue Requirement
Phone 219-647-5694
Fax 219-647-4805
glvajda@nisource.com

Northern Indiana Public Service Company

Depreciation Expense Difference Due to Switch to ELG

Based on Plant and Reserves as of December 31, 2007

	Total Accruals		
	ELG	ALG	Difference
Electric	$ 160,291,823	$ 136,695,966	$ 23,595,857
Common	35,635,828	35,148,584	487,244
Total	$ 195,927,651	$ 171,844,550	$ 24,083,101

Sources:
ELG from Spanos Study, pp. III-13 and III-15 (Exhibit JJS-2, pp. 60 and 62).
ALG from response to OUCC Set 7 DEP-31.

Note: Amounts do not include Sugar Creek.

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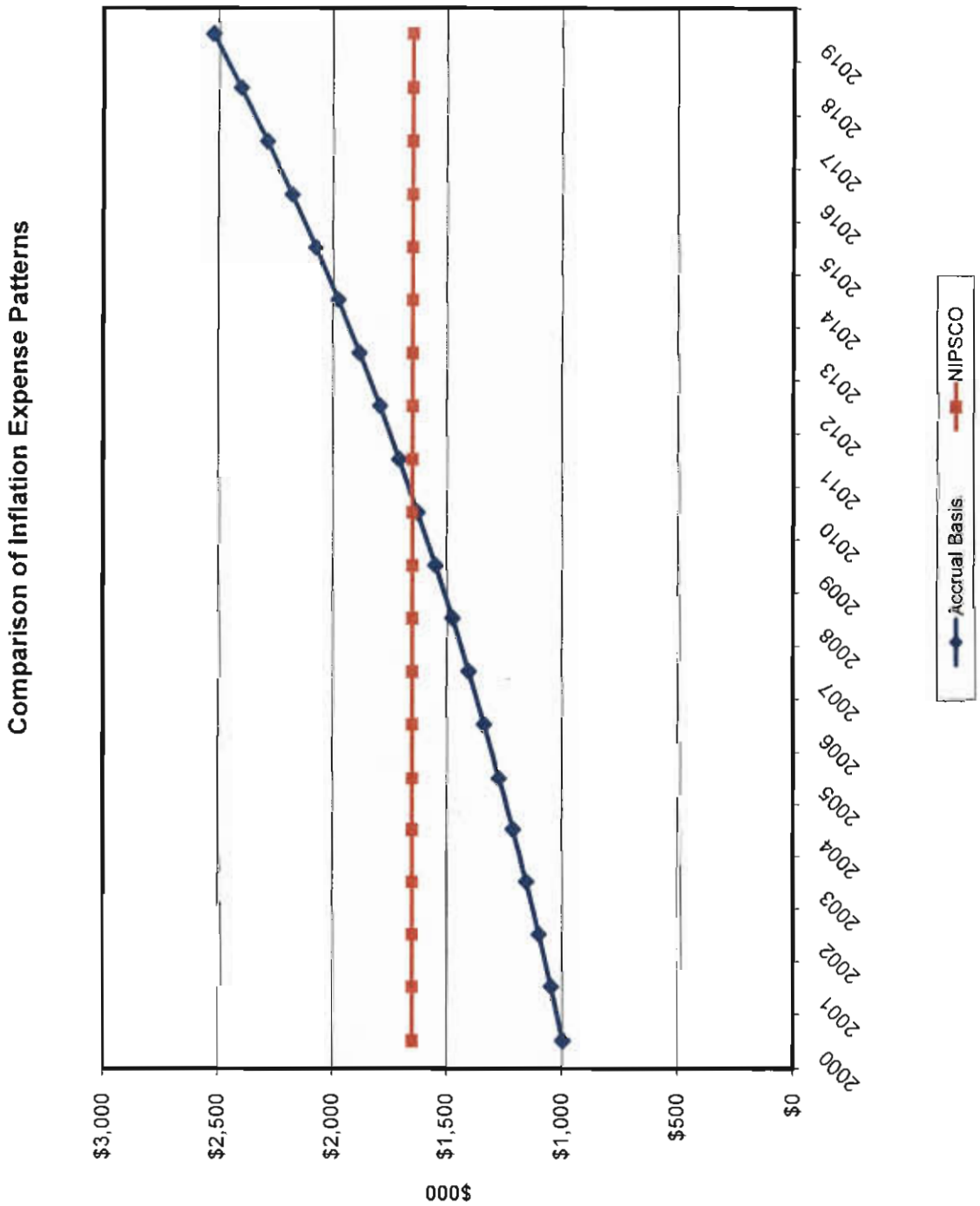
OUCC Request 8 DEP-036
If not provided elsewhere, please provide on diskette or CD all workpapers supporting terminal net salvage (decommissioning) estimates for each account for which terminal net salvage is a factor. Please include all calculations in electronic format (Excel), with all formulae intact.
Objections:
Response:
The Burns & McDonnell decommissioning studies were included as part of OUCC Response Set 7-DEP-002. The information from those studies was utilized in establishing the net salvage percents for each of the steam production units or locations. The net salvage percents are set forth in the spreadsheet attached hereto as OUCC 8-DEP-036 Attachment A.

NORTHERN INDIANA PUBLIC SERVICE COMPANY

DECOMMISSIONING COSTS RELATED TO GENERATING UNITS

UNIT	ESTIMATED RETIREMENT YEAR	MW	ESTIMATED DECOMMISSIONING COSTS ($/KW)	TOTAL DECOMMISSIONING COSTS (CURRENT $)	TOTAL DECOMMISSIONING COSTS (FUTURE $)	SCRAP VALUE ($)	ORIGINAL COST AT 12/31/07	NET SALVAGE
(1)	(2)	(3)	(4)	(5)=(3)*(4)	(6)[a]	(7)	(8)	(9)
STEAM								
MICHIGAN CITY								
2 and 3	2009	120	50 88	19,850,000	20,445,500	950,030	28,352,030	68.76%
12	2034	469	43.22	48,305,000	104,174,141	13,795,720	344,506,147	26.23%
TOTAL MICHIGAN CITY				68,155,000	124,619,641	14,745,750	372,858,177	29.47%
MITCHELL								
4	2009	125	50.77					
5	2009	125	50.77					
6	2009	125	50.77					
11	2009	110	51.10					
TOTAL MITCHELL				67,822,000	69,856,660	6,225,836	171,690,132	37.06%
BAILLY								
7	2023	160	50 01					
8	2028	320	46.49					
TOTAL BAILLY				47,919,000	79,202,806	16,539,752	442,576,155 18	13.71%
SCHAHFER								
14	2036	431	44.05					
15	2039	472	43.15					
17	2043	361	45.59					
18	2046	361	45.59					
TOTAL SCHAHFER				170,347,000	451,817,351	40,540,664	1,628,242,038	22.50%
GRAND TDTAL		3,179		354,243,000	725,496,458		2,815,366,501	25.77%

[a] Column 6 = (Column 5) x (1.03*(Estimated Retirement Year - 2006))


Comparison of Inflation Expense Patterns
$3,000
$2,500
$2,000
$1,500
$1,000
$500
$0
$000
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
Accrual Basis
NIPSCO

Northern Indiana Public Service Company
Comparison of Accrual Accounting Versus NIPSCO Treatment of Inflation

Line	Assumptions:	Year 1		
	Year 1 (2000) Data		2000	
1	Number of Structures		1	structure
2	Service Life		20	years
3	Average age of structure		0	years
4	Remaining life		20	years
5	Present Value of Disposal Cost Per Structure		$20,000	
6	Present Value of Future Disposal Costs L.1 * L5		$20,000	
7	Future inflation rate		5.00%	Assumed
8	Inflated Value of Future Disposal Costs	$	53,065.95	
9	Original Cost of Structure	$	100,000	
10	NIPSCO Approach Recommendation -(L8/L9)		-53.07%	

	Straight Line Recovery of Original PV of Future Removal			Inflation to Original Cost of Future Removal				Annual Expense		
Year	Original Cost of Future Removal BOY	Depraciation Expense	Accumulated Depreciation EOY	PV of Futura Cost BOY	Inflation Expenee	PV of Cost EOY	Cumulative Inflation	Accrual Basis Annual Expense	NIPSCO Annual Expense	NIPSCO Inflation Matching
2000	$20,000	$1,000	$1,000.00	$ 20,000.00	$1,000.00	$21,000.00	$1,000.00	$2,000.00	$2,653.30	$1,653.30
2001	20,000	1,000	2,000.00	21,000.00	1,050.00	22,050.00	2,050.00	2,050.00	2,653.30	1,653.30
2002	20,000	1,000	3,000.00	22,050.00	1,102.50	23,152.50	3,152.50	2,102.50	2,653.30	1,653.30
2003	20,000	1,000	4,000.00	23,152.50	1,157.63	24,310.13	4,310.13	2,157.63	2,653.30	1,653.30
2004	20,000	1,000	5,000.00	24,310.13	1,215.51	25,525.63	5,525.63	2,215.51	2,653.30	1,653.30
2005	20,000	1,000	6,000.00	25,525.63	1,276.28	26,801.91	6,801.91	2,276.28	2,653.30	1,653.30
2006	20,000	1,000	7,000.00	28,801.91	1,340.10	28,142.01	8,142.01	2,340.10	2,653.30	1,653.30
2007	20,000	1,000	8,000.00	28,142.01	1,407.10	29,549.11	9,549.11	2,407.10	2,653.30	1,653.30
2008	20,000	1,000	9,000.00	29,549.11	1,477.46	31,026.56	11,026.56	2,477.46	2,653.30	1,653.30
2009	20,000	1,000	10,000.00	31,026.56	1,551.33	32,577.89	12,577.89	2,551.33	2,653.30	1,653.30
2010	20,000	1,000	11,000.00	32,577.89	1,628.89	34,206.79	14,206.79	2,628.89	2,653.30	1,653.30
2011	20,000	1,000	12,000.00	34,206.79	1,710.34	35,917.13	15,917.13	2,710.34	2,653.30	1,653.30
2012	20,000	1,000	13,000.00	35,917.13	1,795.86	37,712.98	17,712.98	2,795.86	2,653.30	1,653.30
2013	20,000	1,000	14,000.00	37,712.98	1,885.65	39,598.83	19,598.63	2,885.65	2,653.30	1,653.30
2014	20,000	1,000	15,000.00	39,598.83	1,979.93	41,578.56	21,578.56	2,979.93	2,653.30	1,653.30
2015	20,000	1,000	16,000.00	41,578.56	2,078.93	43,657.49	23,657.49	3,078.93	2,653.30	1,653.30
2016	20,000	1,000	17,000.00	43,657.49	2,182.87	45,840.37	25,840.37	3,162.67	2,653.30	1,653.30
2017	20,000	1,000	18,000.00	45,840.37	2,292.02	48,132.36	28,132.38	3,292.02	2,653.30	1,653.30
2018	20,000	1,000	19,000.00	48,132.38	2,406.62	50,539.00	30,539.00	3,406.62	2,653.30	1,653.30
2019	20,000	1,000	20,000.00	50,539.00	2,526.95	53,065.95	33,065.95	3,526.95	2,653.30	1,653.30
		$20,000.00			$33,065.95			$53,065.95	$53,066.00	

Comparison of Inflation Expense Patterns

Year	Accrual Basis Annual Inflation	NIPSCO Annual Inflation
2000	$1,000.00	$1,653.30
2001	1,050.00	1,653.30
2002	1,102.50	1,653.30
2003	1,157.63	1,653.30
2004	1,215.51	1,653.30
2005	1,276.28	1,653.30
2006	1,340.10	1,653.30
2007	1,407.10	1,653.30
2008	1,477.46	1,653.30
2009	1,551.33	1,653.30
2010	1,628.89	1,653.30
2011	1,710.34	1,653.30
2012	1,795.86	1,653.30
2013	1,885.65	1,653.30
2014	1,979.93	1,653.30
2015	2,078.93	1,653.30
2016	2,182.87	1,653.30
2017	2,292.02	1,653.30
2018	2,406.62	1,653.30
2019	2,526.95	1,653.30

NORTHERN INDIANA PUBLIC SERVICE COMPANY

ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AT DECEMBER 31, 2007
SNAVELY KING RECOMMENDATIONS

DEPRECIABLE GROUP	ORIGINAL COST AT DECEMBER 31, 2007 (1)	BOOK DEPRECIATION RESERVE (2)	FUTURE ACCRUALS (3)=(1)-(2)-((1)*(5))	ASL/ SURVIVOR CURVE (4)		NET SALVAGE (5)	COMPOSITE REMAINING LIFE (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)=(3)/(6)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(1)
STEAM PRODUCTION PLANT									
311.00 STRUCTURES AND IMPROVEMENTS									
Fully Depreciated									
D H Mitchell - Units 4, 5, 6 and 11	1,117,909	1,117,909	-	100-R2.5	*	-	-	-	-
D H Mitchell - Units 5 and 6	5,464,662	5,464,662	-	100-R2.5	*	-	-	-	-
D H Mitchell Generating Station	12,680,346	12,680,346	-	100-R2.5	*	-	-	-	-
D H Mitchell - Unit 4	3,203,360	3,203,360	-	100-R2.5	*	-	-	-	-
D H Mitchell - Unit 5	541,644	541,844	-	100-R2.5	*	-	-	-	-
D H Mitchell - Unit 6	441,586	441,568	-	100-R2.5	*	-	-	-	-
D H Mitchell - Unit 11	4,613,715	4,613,715	-	100-R2.5	*	-	-	-	-
Michigan City - Units 2 and 3	478,402	478,402	-	100-R2.5	*	-	-	-	-
Michigan City - Unit 2	42,369	42,369	-	100-R2.5	*	-	-	-	-
Michigan City - Unit 3	9,647	9,847	-	100-R2.5	*	-	-	-	-
Total Fully Depreciated Account 311	*28,792,041*	*28,792,041*	-					-	-
Depreciable									
Bailly - Units 7 and 8	22,054,618	16,951,392	4,567,652	100-R2.5	*	(6.64)	20.1	227,246	1.03
Bailly Generating Station	12,432,495	10,137,106	3,120,904	100-R2.5	*	(6.64)	20.2	154,500	1.24
Bailly - Unit 7	6,431,461	6,464,296	394,212	100-R2.5	*	(6.64)	15.3	25,765	0.40
Bailly - Unit 8	10,957,954	10,203,245	1,462,316	100-R2.5	*	(6.64)	20.1	73,747	0.67
Michigan City - Units 2, 3 and 12	8,034,076	11,751,791	1,637,800	100-R2.5	*	(68.66)	26.0	62,992	0.78
Michigan City Generating Station	25,636,546	16,098,186	12,329,385	100-R2.5	*	(10.02)	26.1	472,390	1.63
Michigan City - Unit 12	25,267,047	24,024,325	3,796,465	100-R2.5	*	(10.02)	25.7	147,723	0.58
R M Schahfer - Units 14 and 15	9,038,085	8,988,943	2,706,704	100-R2.5	*	(7.10)	30.4	89,102	0.99
R M Schahfer - Units 14, 15, 17 and 18	31,669,201	21,799,759	12,117,955	100-R2.5	*	(7.10)	36.7	330,190	1.04
R M Schahfer - Units 17 and 18	56,632,982	39,632,041	22,963,863	100-R2.5	*	(7.10)	36.6	824,019	1.08
R M Schahfer Generating Station	43,094,530	25,263,690	20,890,552	100-R2.5	*	(7.10)	37.0	564,610	1.31
R M Schahfer - Unit 14	32,400,003	29,146,722	5,553,860	100-R2.5	*	(7.10)	27.5	201,952	0.62
R M Schahfer - Unit 15	33,616,571	28,069,090	7,936,399	100-R2.5	*	(7.10)	30.3	281,927	0.78
R M Schahfer - Unit 17	65,160,270	61,608,668	29,819,361	100-R2.5	*	(7.10)	34.1	666,604	1.02
R M Schahfer - Unit 18	57,796,067	36,684,760	25,036,970	100-R2.5	*	(7.10)	36.9	678,509	1.17
Total Depreciable Account 311	*462,465,908*	*347,184,038*	*154,156,280*					*4,783,276*	*1.03*
Total Account 311	491,257,948	375,976,079	154,156,280					4,783,276	0.97
BOILER PLANT EQUIPMENT									
312.10 Boiler Plant Equipment									
Fully Depreciated									
D H Mitchell - Units 4 and 5	1,477,244	1,477,244	-	45-S0	*	-	-	-	-
D H Mitchell - Units 4, 5 and 6	453,563	453,563	-	45-S0	*	-	-	-	-
D H Mitchell - Units 4, 5, 6 and 11	3,711,172	3,711,172	-	45-S0	*	-	-	-	-
D H Mitchell - Units 5 and 6	1,129,049	1,129,049	-	45-S0	*	-	-	-	-
D H Mitchell Generating Station	27,634,041	27,634,041	-	45-S0	*	-	-	-	-
D H Mitchell - Unit 4	11,026,585	11,026,565	-	45-S0	*	-	-	-	-
D H Mitchell - Unit 5	13,290,626	13,290,826	-	45-S0	*	-	-	-	-
D H Mitchell - Unit 6	15,960,775	15,960,775	-	45-S0	*	-	-	-	-
D H Mitchell - Unit 11	14,974,709	14,974,709	-	45-S0	*	-	-	-	-
Michigan City - Units 2 and 3	9,915,400	9,915,400	-	45-S0	*	-	-	-	-
Michigan City - Unit 2	630,226	830,226	-	45-S0	*	-	-	-	-
Michigan City - Unit 3	337,263	337,283	-	45-S0	*	-	-	-	-
Total Fully Depreciated Account 312.10	*100,760,872*	*100,760,872*	-					-	-

NORTHERN INDIANA PUBLIC SERVICE COMPANY

ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AT DECEMBER 31, 2007
SNAVELY KING RECOMMENDATIONS

DEPRECIABLE GROUP	ORIGINAL COST AT DECEMBER 31, 2007	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	ASL/ SURVIVOR CURVE	NET SALVAGE	COMPOSITE REMAINING LIFE	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE
	(1)	(2)	(3)=(1)-(2)-((1)*(5))	(4)	(5)	(6)	(7)=(3)/(6)	(8)=(7)/(1)
312.10 Boiler Plent Equipment, cont.								
Depreciable								
Beilly - Units 7 and 8	31,832,911	20,902,504	13,044,112	45-S0 *	(6.64)	17.6	741,143	2.33
Bailly Generating Station	114,778,675	36,944,607	85,455,372	45-S0 *	(6.64)	16.7	4,569,606	3.96
Bailly - Unit 7	50,875,957	28,203,597	26,050,523	45-S0 *	(6.64)	14.4	1,809,064	3.56
Bailly - Unit 6	78,852,941	54,676,551	27,066,145	45-S0 *	(6.64)	17.3	1,564,517	2.04
Michigan City Generating Station	84,861,343	36,607,824	58,758,626	45-S0 *	(10.02)	22.6	2,489,326	2.93
Michigan City - Unit 12	119,819,910	73,721,418	56,104,447	45-S0 *	(10.02)	21.9	2,653,171	2.21
R M Schahfer - Units 14 and 15	22,997,865	11,848,042	12,782,671	45-S0 *	(7.10)	25.0	511,307	2.22
R M Schahfer - Units 14, 15, 17 and 16	9,515,149	8,172,035	4,016,690	45-S0 *	(7.10)	25.9	155,162	1.63
R M Schahfer - Units 17 and 16	44,705,449	24,659,124	23,220,411	45-S0 *	(7.10)	27.3	650,565	1.90
R M Schehfer Generating Station	86,164,240	28,550,769	42,311,132	45-S0 *	(7.10)	26.8	1,469,137	2.22
R M Schahfer - Unit 14	230,980,731	111,161,374	136,216,986	45-S0 *	(7.10)	23.7	5,747,637	2.49
R M Schahfer - Unit 15	162,697,879	107,085,624	67,183,591	45-S0 *	(7.10)	23.7	2,634,751	1.74
R M Schahfer - Unit 17	157,507,778	108,316,729	60,374,099	45-S0 *	(7.10)	24.6	2,454,232	1.56
R M Schahfer - Unit 18	167,141,755	101,504,255	77,504,564	45-S0 *	(7.10)	26.5	2,924,701	1.75
Total Depreciable Account 312.10	*1,340,532,380*	*750,334,453*	*690,091,372*				*30,774,516*	*2.30*
Total Account 312.10	1,441,293,251	651,095,325	690,091,372				30,774,516	2.14
312.20 Boiler Plant - Moblie Fuel Hdlg/Strg								
Fully Depreciated								
D H Mitchell Generating Station	2,218,917	2,216,917	-	45-S0 *	-	-	-	-
Total Fully Depreciated Account 312.20								
Depreciable								
Bailly - Units 7 and 6	127,235	130,969	4,714	45-S0 *	(6.64)	17.9	263	0.21
Bailly Generating Station	4,871,467	2,728,618	2,466,115	45-S0 *	(6.64)	18.5	133,303	2.74
Michigan City Generating Station	3,040,053	2,648,697	695,969	45-S0 *	(10.02)	22.6	30,525	1.00
Michigan City - Unit 12	171,112	38,006	150,251	45-S0 *	(10.02)	23.6	6,313	3.69
R M Schahfer - Units 14, 15, 17 and 18	370,727	97,342	299,706	45-S0 *	(7.10)	31.2	9,606	2.59
R M Schahfer Generating Station	10,131,818	4,019,966	6,830,977	45-S0 *	(7.10)	30.9	221,067	2.16
R M Schahfer - Unit 15	181,951	210,185	(36,735)	45-S0 *	(7.10)	22.0	(1,670)	-1.03
Total Depreciable Account 312.20	*18,874,162*	*9,874,003*	*10,410,997*				*399,408*	*2.12*
Total Account 312.20	21,091,079	12,090,920	10,410,997				399,406	1.89
312.30 Boiler Plent - Unit Train Coal Cars								
Fully Depreciated								
Bailly - Units 7 and 8	2,823,046	2,623,046	-	25-R2.5	-	-	-	-
Bailly Generating Station	17,293	17,293	-	25-R2.5	-	-	-	-
Total Fully Depreciated Account 312.30	*2,840,339*	*2,840,339*	-				-	-
Depreciable								
R M Schahfer - Units 14, 15, 17 end 18	970,020	58,313	811,971	25-R2.5	10.28	19.9	40,803	4.21
R M Schahfer Generating Station	242,505	14,578	202,993	25-R2.5	10.28	19.9	10,201	4.21
Total Depreciable Account 312.30	*1,212,525*	*72,891*	*1,014,964*				*51,003*	*4.21*
Total Account 312.30	4,052,864	2,913,230	1,014,964				51,003	1.26
312.40 Boiler Plant - SO2 Plant Equipment								
R M Schahfer - Units 17 and 18	31,302,027	4,507,249	26,794,778	45-S0 *	-	26.5	940,166	3.00
R M Schahfer Generating Station	11,014,344	1,077,555	9,936,769	45-S0 *	-	30.0	331,226	3.01
R M Schahfer - Unit 17	38,328,490	6,164,702	28,161,788	45-S0 *	-	24.5	1,149,461	3.16
R M Schahfer - Unit 18	34,823,297	6,969,394	27,853,903	45-S0 *	-	26.4	1,055,072	3.03
Total Account 312.40	113,486,157	20,718,900	92,747,257				3,475,927	3.06

NORTHERN INDIANA PUBLIC SERVICE COMPANY

ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AT DECEMBER 31, 2007
SNAVELY KING RECOMMENDATIONS

DEPRECIABLE GROUP	ORIGINAL COST AT DECEMBER 31, 2007 (1)	BOOK DEPRECIATION RESERVE (2)	FUTURE ACCRUALS (3)=(1)-(2)-((1)*(5))	ASL/ SURVIVOR CURVE (4)	NET SALVAGE (5)	COMPOSITE REMAINING LIFE (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)=(3)/(6)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(1)
312.50 Boiler Plant - Coal Pile Base								
Fully Depreciated								
D H Mitchell Generating Station	2,640,882	2,840,862	-	SQUARE *	-	-	-	-
Total Fully Depreciated Account 312.50								
Depreciable								
Bailly - Units 7 and 8	949,799	930,140	82,728	SQUARE *	(6.64)	20.5	4,035	0.42
Michigan City Generating Station	864,033	852,498	(121,927)	SQUARE *	(10.02)	26.5	(4,601)	-0.69
R M Schahfer - Units 14 and 15	1,629,921	2,092,256	(132,411)	SQUARE *	(7.10)	31.5	(4,204)	-0.23
R M Schahfer - Units 17 and 18	2,400,176	2,365,435	165,154	SQUARE *	(7.10)	38.5	4,809	0.20
Total Depreciable Account 312.50	*5,843,930*	*6,260,328*	*13,542*				*40*	*0.00*
Total Account 312.50	8,884,792	9,101,190	13,542				40	0.00
Total Account 312	1,588,588,144	695,919,585	794,278,131				34,700,894	2.16
314.00 TURBO-GENERATOR UNITS								
Fully Depreciated								
D H Mitchell - Units 4 and 5	82,957	82,957	-	50-S1 *	-	-	-	-
D H Mitchell - Units 4, 5, 8 and 11	72,506	72,506	-	50-S1 *	-	-	-	-
D H Mitchell - Units 5 and 8	520,326	520,328	-	50-S1 *	-	-	-	-
D H Mitchell Generating Station	4,081,504	4,081,504	-	50-S1 *	-	-	-	-
D H Mitchell - Unit 4	6,958,893	8,958,893	-	50-S1 *	-	-	-	-
D H Mitchell - Unit 5	8,643,575	8,643,575	-	50-S1 *	-	-	-	-
D H Mitchell - Unit 8	3,364,430	3,384,430	-	50-S1 *	-	-	-	-
D H Mitchell - Unit 11	5,183,599	5,183,599	-	50-S1 *	-	-	-	-
Michigan City - Units 2 and 3	1,198,747	1,198,747	-	50-S1 *	-	-	-	-
Michigan City - Unit 2	2,403,348	2,403,348	-	50-S1 *	-	-	-	-
Michigan City - Unit 3	2,298,372	2,298,372	-	50-S1 *	-	-	-	-
Total Fully Depreciated Account 314	*34,788,257*	*34,786,257*	-				-	-
Depreciable								
Bailly - Units 7 and 8	2,657,803	2,706,581	127,487	50-S1 *	(6.64)	14.3	8,915	0.34
Bailly Generating Station	3,887,643	1,799,202	2,325,252	50-S1 *	(6.64)	19.2	121,107	3.13
Bailly - Unit 7	38,770,929	23,799,820	15,412,699	50-S1 *	(6.64)	14.7	1,046,483	2.65
Bailly - Unit 8	22,000,737	17,728,092	5,733,493	50-S1 *	(6.64)	17.4	329,511	1.50
Michigan City Generating Station	2,825,582	2,440,440	888,268	50-S1 *	(10.02)	22.0	30,376	1.08
Michigan City - Unit 12	40,836,880	38,793,860	7,914,593	50-S1 *	(10.02)	20.4	387,970	0.95
R M Schahfer - Units 14 and 15	1,104,031	757,594	424,823	50-S1 *	(7.10)	24.9	17,061	1.55
R M Schahfer - Units 14 and 17	89,017	28,338	67,001	50-S1 *	(7.10)	30.7	2,182	2.45
R M Schahfer - Units 14, 15, 17 and 18	1,096,193	809,455	364,587	50-S1 *	(7.10)	25.9	14,076	1.28
R M Schahfer - Units 14, 17 and 18	115,756	39,101	64,874	50-S1 *	(7.10)	32.1	2,644	2.28
R M Schahfer - Units 15 and 18	85,912	28,461	44,131	50-S1 *	(7.10)	31.4	1,405	2.13
R M Schahfer - Units 17 and 18	1,882,078	784,595	1,209,691	50-S1 *	(7.10)	31.1	38,897	2.09
R M Schahfer Generating Station	4,515,838	2,630,987	2,205,279	50-S1 *	(7.10)	28.9	76,307	1.69
R M Schahfer - Unit 14	45,150,042	34,820,474	13,535,221	50-S1 *	(7.10)	22.6	598,904	1.33
R M Schahfer - Unit 15	53,083,407	38,155,858	18,696,873	50-S1 *	(7.10)	24.4	766,257	1.44
R M Schahfer - Unit 17	83,877,474	59,508,497	30,110,078	50-S1 *	(7.10)	25.8	1,167,057	1.39
R M Schahfer - Unit 18	88,174,461	58,139,082	38,295,765	50-S1 *	(7.10)	27.5	1,319,846	1.50
Total Depreciable Account 314	*367,693,160*	*280,968,212*	*135,219,894*				*5,930,999*	*1.53*
Total Account 314	422,479,417	315,754,489	135,219,894				5,930,999	1.40

NORTHERN INDIANA PUBLIC SERVICE COMPANY

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SNAVELY KING RECOMMENDATIONS

DEPRECIABLE GROUP	ORIGINAL COST AT DECEMBER 31, 2007 (1)	BOOK DEPRECIATION RESERVE (2)	FUTURE ACCRUALS (3)=(1)-(2)-((1)*(5))	ASL/ SURVIVOR CURVE (4)	NET SALVAGE (5)	COMPOSITE REMAINING LIFE (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)=(3)/(6)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(1)
315.00 ACCESSORY ELECTRIC EQUIPMENT								
Fully Depreciated								
D H Mitchell - Units 4 and 5	3,406	3,406	-	55-L1.5 *	-	-	-	-
D H Mitchell - Units 4, 5 and 8	23,450	23,450	-	55-L1.5 *	-	-	-	-
D H Mitchell - Units 4, 5, 6 and 11	113,519	113,519	-	55-L1.5 *	-	-	-	-
D H Mitchell - Units 5 and 6	2,223,011	2,223,011	-	55-L1.5 *	-	-	-	-
D H Mitchell Generating Station	7,240,293	7,240,293	-	55-L1.5 *	-	-	-	-
D H Mitchell - Unit 4	2,049,205	2,049,205	-	55-L1.5 *	-	-	-	-
D H Mitchell - Unit 5	815,536	815,538	-	55-L1.5 *	-	-	-	-
D H Mitchell - Unit 8	907,664	907,864	-	55-L1.5 *	-	-	-	-
D H Mitchell - Unit 11	4,304,167	4,304,187	-	55-L1.5 *	-	-	-	-
Michigan City - Units 2 and 3	1,359,508	1,359,508	-	55-L1.5 *	-	-	-	-
Michigan City - Unit 2	194,267	194,267	-	55-L1.5 *	-	-	-	-
Michigan City - Unit 3	57,645	57,645	-	55-L1.5 *	-	-	-	-
Total Fully Depreciated Account 315	*19,292,091*	*19,292,091*	-				-	-
Depreciable								
Bailly - Units 7 and 6	2,979,569	1,631,726	1,345,685	55-L1.5 *	(6.64)	18.7	71,962	2.42
Bailly Generating Station	7,369,637	2,947,095	4,933,214	55-L1.5 *	(6.64)	19.4	254,289	3.44
Bailly - Unit 7	10,162,902	9,369,868	1,469,361	55-L1.5 *	(6.64)	13.9	105,709	1.04
Bailly - Unit 8	16,563,650	12,185,605	5,477,871	55-L1.5 *	(6.84)	18.2	300,971	1.82
Michigan City Generating Station	18,665,626	10,315,327	10,242,598	55-L1.5 *	(10.02)	23.9	428,561	2.29
Michigan City - Unit 12	16,269,334	15,946,490	4,153,431	55-L1.5 *	(10.02)	21.2	195,917	1.07
R M Schahfer - Units 14 and 15	3,109,866	1,950,637	1,379,817	55-L1.5 *	(7.10)	25.9	53,267	1.71
R M Schahfer - Units 14, 15, 17 and 18	3,276,235	1,703,425	1,607,565	55-L1.5 *	(7.10)	30.3	59,856	1.82
R M Schahfer - Units 17 and 18	34,020,867	24,103,527	12,332,829	55-L1.5 *	(7.10)	27.3	451,745	1.33
R M Schahfer Generating Station	27,187,536	19,017,280	10,100,570	55-L1.5 *	(7.10)	27.8	383,330	1.34
R M Schahfer - Unit 14	22,873,364	18,630,160	5,667,213	55-L1.5 *	(7.10)	22.4	253,001	1.11
R M Schahfer - Unit 15	21,080,108	15,385,937	7,169,436	55-L1.5 *	(7.10)	24.7	290,261	1.38
R M Schahfer - Unit 17	37,997,042	27,662,673	12,832,159	55-L1.5 *	(7.10)	26.0	493,545	1.30
R M Schahfer - Unit 18	31,433,207	20,836,270	12,828,894	55-L1.5 *	(7.10)	28.0	458,188	1.46
Total Depreciable Account 315	*255,030,562*	*182,306,241*	*91,739,844*				*3,780,379*	*1.48*
Total Account 315	274,322,653	201,598,332	91,739,844				3,780,379	1.38
318.00 MISCELLANEOUS POWER PLANT EQUIPMENT								
Fully Depreciated								
D H Mitchell - Units 4, 5, 6 and 11	1,269,835	1,269,835	-	55-R2 *	-	-	-	-
D H Mitchell - Units 5 and 6	29,770	29,770	-	55-R2 *	-	-	-	-
D H Mitchell Generating Station	513,457	513,457	-	55-R2 *	-	-	-	-
D H Mitchell - Unit 4	76,129	78,129	-	55-R2 *	-	-	-	-
D H Mitchell - Unit 5	20,756	20,758	-	55-R2 *	-	-	-	-
D H Mitchell - Unit 6	19,891	19,891	-	55-R2 *	-	-	-	-
D H Mitchell - Unit 11	194,865	194,865	-	55-R2 *	-	-	-	-
Michigan City - Units 2 and 3	114,086	114,088	-	55-R2 *	-	-	-	-
Total Fully Depreciated Account 316	*2,238,793*	*2,238,793*	-				-	-
Depreciable								
Bailly - Units 7 and 8	2,950,691	1,734,752	1,411,685	55-R2 *	(6.64)	19.5	72,403	2.45
Bailly Generating Station	1,497,707	945,827	651,328	55-R2 *	(6.64)	19.4	33,574	2.24
Bailly - Unit 7	269,755	203,275	84,392	55-R2 *	(6.64)	15.1	5,589	2.07
Bailly - Unit 8	839,482	492,233	189,710	55-R2 *	(6.64)	19.3	9,830	1.54
Michigan City - Units 2, 3 and 12	1,060,253	993,743	806,606	55-R2 *	(66.88)	24.3	33,194	3.07
Michigan City Generating Station	1,831,912	1,416,850	376,579	55-R2 *	(10.02)	23.8	15,957	0.98
Michigan City - Unit 12	2,774,987	2,339,440	713,801	55-R2 *	(10.02)	23.8	29,983	1.08

NORTHERN INDIANA PUBLIC SERVICE COMPANY

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DEPRECIABLE GROUP	ORIGINAL COST AT DECEMBER 31, 2007	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	ASL/ SURVIVOR CURVE		NET SALVAGE	COMPOSITE REMAINING LIFE	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE
	(1)	(2)	(3)=(1)-(2)-((1)*(5))	(4)		(5)	(6)	(7)=(3)/(6)	(8)=(7)/(1)
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT, cont.									
R M Schahfer - Units 14 and 15	869,431	476,865	236,096	55-R2	*	(7.10)	27.5	8,658	1.29
R M Schahfer - Units 14, 15, 17 and 18	9,296,634	8,950,598	3,006,096	55-R2	*	(7.10)	30.3	99,211	1.07
R M Schahfer - Units 17 and 18	1,814,481	771,671	1,171,636	55-R2	*	(7.10)	33.6	34,670	1.92
R M Schahfer Generating Station	1,204,364	561,176	708,696	55-R2	*	(7.10)	33.3	21,282	1.77
R M Schehfer - Unit 14	2,497,587	2,334,802	340,092	55-R2	*	(7.10)	24.1	14,112	0.57
R M Schahfer - Unit 15	2,672,566	2,234,641	627,499	55-R2	*	(7.10)	26.5	23,679	0.89
R M Schahfar - Unit 17	3,562,435	2,806,602	1,008,766	55-R2	*	(7.10)	28.7	35,149	0.99
R M Schahfer - Unit 18	3,917,262	2,617,327	1,578,081	55-R2	*	(7.10)	31.4	50,257	1.26
Total Depreciable Account 316	*36,479,546*	*26,904,003*	*12,913,026*					*487,747*	*1.34*
Total Account 316	38,718,339	29,142,796	12,913,026					487,747	1.26
TOTAL STEAM PRODUCTION PLANT	2,615,386,501	1,818,391,241	1,166,307,174					49,663,295	1.76
HYDRO PLANT									
331.00 STRUCTURES AND IMPROVEMENTS									
Norway Generating Station	1,055,735	164,980	1,156,146	90-R2.5	*	(27.22)	28.5	40,637	3.65
Norway Substation	22,138	5,597	22,503	90-R2.5	*	(26.93)	28.8	761	3.53
Oakdale Generating Station	1,872,853	294,661	2,060,364	90-R2.5	*	(26.84)	28.9	71,985	3.84
Oakdale Substation	6,923	1,751	7,037	90-R2.5	*	(26.93)	28.8	244	3.53
Total Account 331	2,957,449	467,189	3,268,051					113,647	3.64
332.00 RESERVOIRS, DAMS AND WATERWAYS									
Norway Generating Station	2,011,677	136,621	2,519,013	100-R2.5	*	(32.01)	27.6	90,812	4.50
Norway Substation	46,843	3,285	56,011	100-R2.5	*	(30.86)	29.0	2,000	4.27
Oakdale Generating Station	3,911,909	249,691	4,916,301	100-R2.5	*	(32.11)	27.7	177,556	4.54
Total Account 332	5,970,429	389,597	7,495,326					270,168	4.53
333.00 WATER WHEELS, TURBINES & GENERATORS									
Norway Generating Station	1,540,840	747,623	1,190,183	70-R2.5	*	(25.78)	28.4	41,908	2.72
Oakdale Generating Station	2,933,102	1,797,436	1,902,455	70-R2.5	*	(26.14)	27.8	68,434	2.33
Oakdale Substation	59,723	7,362	67,473	70-R2.5	*	(25.30)	29.2	2,311	3.87
Total Account 333	4,533,466	2,552,421	3,160,110					112,652	2.48
334.00 ACCESSORY ELECTRIC EQUIPMENT									
Norway Generating Station	1,532,673	419,442	1,290,904	55-L1.5	*	(11.59)	26.0	49,650	3.24
Norway Substation	24,087	10,670	16,410	55-L1.5	*	(12.52)	23.4	701	2.91
Oakdale Generating Station	355,846	125,480	273,360	55-L1.5	*	(12.08)	24.6	11,112	3.12
Oakdale Substation	95,866	25,107	81,607	55-L1.5	*	(11.52)	26.2	3,122	3.26
Total Account 334	2,008,453	580,699	1,682,481					64,586	3.22
335.00 MISCELLANEOUS POWER PLANT EQUIPMENT									
Norway Generating Station	34,197	34,197	0	50-L1.5	*	-	-	-	-
Oakdale Generating Station	58,205	110,053	(51,848)	50-L1.5	*	-	-	-	-
Total Account 335	92,402	144,250	(51,848)					-	-
TOTAL HYDRO PLANT	15,562,198	4,154,158	15,534,120					561,054	3.61

NORTHERN INDIANA PUBLIC SERVICE COMPANY

ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AT DECEMBER 31, 2007
SNAVELY KING RECOMMENDATIONS

DEPRECIABLE GROUP	ORIGINAL COST AT DECEMBER 31, 2007 (1)	BOOK DEPRECIATION RESERVE (2)	FUTURE ACCRUALS (3)=(1)-(2)-((1)*(5))	ASL/ SURVIVOR CURVE (4)	NET SALVAGE (5)	COMPOSITE REMAINING LIFE (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)=(3)/(6)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(1)
GAS TURBINE PLANT								
341.00 STRUCTURES AND IMPROVEMENTS								
Fully Depreciated								
Bailly - Unit 10	209,096	209,096	-	45-S3 *	-	-	-	-
D H Mitchell - Unit 9A	93,581	93,581	-	45-S3 *	-	-	-	-
Total Fully Depreciated Account 341	*302,677*	*302,677*	-				-	-
Depreciable								
R M Schahfer - Units 16A and 16B	640,108	801,669	64,491	45-S3 *	(3.10)	12.3	5,243	0.82
R M Schahfer - Unit 16A	718,563	756,045	(14,781)	45-S3 *	(3.16)	11.8	(1,251)	-0.17
R M Schahfer - Unit 16B	169,194	174,178	386	45-S3 *	(3.16)	11.8	31	0.02
Total Depreciable Account 341	*1,727,665*	*1,731,892*	*50,098*				*4,023*	*0.23*
Total Account 341	2,030,542	2,034,569	50,098				4,023	0.20
342.00 FUEL HOLDERS, PRODUCTS & ACCESSORIES								
Fully Depreciated								
Bailly - Unit 10	43,439	43,439	-	50-S3 *	-	-	-	-
D H Mitchell - Unit 9A	314,702	314,702	-	50-S3 *	-	-	-	-
D H Mitchell Generating Station	47,120	47,120	-	50-S3 *	-	-	-	-
Total Fully Depreciated Account 342	*405,260*	*405,260*	-				-	-
Depreciable								
Bailly Generating Station	413,347	434,240	7,122	50-S3 *	(6.78)	11.5	619	0.15
R M Schahfer - Units 16A and 16B	4,870,824	5,161,500	39,454	50-S3 *	(6.78)	11.5	3,431	0.07
R M Schahfer Generating Station	28,901	28,151	2,677	50-S3 *	(6.66)	12.0	223	0.77
R M Schahfer - Unit 16A	2,213,632	2,203,530	157,619	50-S3 *	(6.66)	12.0	13,135	0.59
R M Schahfer - Unit 16B	1,298,101	1,242,023	142,292	50-S3 *	(6.64)	12.1	11,760	0.91
Total Depreciable Account 342	*8,824,805*	*9,069,444*	*349,163*				*29,168*	*0.33*
Total Account 342	9,230,065	9,474,704	349,163				29,188	0.32
343.00 PRIME MOVERS								
Fully Depreciated								
D H Mitchell Generating Station	4,464	4,484	-	45-R3 *	-	-	-	-
D H Mitchell - Unit 9A	1,600,364	1,600,364	-	45-R3 *	-	-	-	-
Total Fully Depreciated Account 343	*1,604,828*	*1,604,828*	-				-	-
Depreciable								
Bailly Generating Station	421,259	162,886	278,958	45-R3 *	(9.63)	11.4	24,470	5.81
Bailly - Unit 10 Regulating Station	207,048	87,146	139,849	45-R3 *	(9.63)	11.4	12,287	5.92
Bailly - Unit 10	2,549,987	2,419,891	375,767	45-R3 *	(9.63)	11.4	32,962	1.29
R M Schahfer - Units 16A and 16B	3,710,026	3,567,706	495,811	45-R3 *	(9.52)	11.7	42,360	1.14
R M Schahfer - Unit 16A	8,147,606	6,476,741	458,878	45-R3 *	(9.67)	11.3	40,608	0.50
R M Schahfer - Unit 16B	9,136,724	9,465,840	554,559	45-R3 *	(9.67)	11.3	49,076	0.54
Total Depreciable Account 343	*24,172,649*	*24,200,210*	*2,303,620*				*201,744*	*0.83*
Total Account 343	25,777,477	25,605,038	2,303,820				201,744	0.78

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SNAVELY KING RECOMMENDATIONS

DEPRECIABLE GROUP	ORIGINAL COST AT DECEMBER 31, 2007	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	ASL/ SURVIVOR CURVE		NET SALVAGE	COMPOSITE REMAINING LIFE	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE
	(1)	(2)	(3)=(1)-(2)-((1)*(5))	(4)		(5)	(6)	(7)=(3)/(6)	(8)=(7)/(1)
344.00 GENERATORS									
Fully Depreciated									
Bailly - Unit 10 Regulating Station	28,231	28,231	-	45-R2.5	*	-	-	-	-
Bailly - Unit 10	542,631	542,631	-	45-R2.5	*	-	-	-	-
D H Mitchell - Unit 9A	362,847	362,847	-	45-R2.5	*	-	-	-	-
R M Schahfer - Unit 16A	2,365,606	2,365,606	-	45-R2.5	*	-	-	-	-
R M Schahfer - Unit 16B	2,365,606	2,365,606	-	45-R2.5	*	-	-	-	-
Total Fully Depreciated Account 344	*5,705,324*	*5,705,324*	-					-	-
Depreciable									
R M Schahfer Generating Station	65,163	583,811	(517,802)	45-R2.5	*	(1.30)	34.9	1,907	2.93
Total Account 344	5,770,487	6,289,135	(517,802)					1,907	-
345.00 ACCESSORY ELECTRIC EQUIPMENT									
Fully Depreciated									
D H Mitchell - Unit 9A	532,231	532,231	-	35-S3	*	-	-	-	-
D H Mitchell Generating Station	19,426	19,426	-	35-S3	*	-	-	-	-
Total Fully Depreciated Account 345	*551,657*	*551,657*	-					-	-
Depreciable									
Bailly Generating Station	123,764	112,625	21,003	35-S3	*	(7.95)	5.9	3,560	2.88
Bailly - Unit 10	602,172	498,122	148,677	35-S3	*	(7.44)	7.6	19,569	3.25
R M Schahfer - Units 16A and 16B	24,933	21,006	5,733	35-S3	*	(7.24)	8.3	691	2.77
R M Schahfer - Unit 16A	814,666	569,950	298,712	35-S3	*	(6.63)	10.6	28,180	3.46
R M Schahfer - Unit 16B	802,521	559,980	295,711	35-S3	*	(6.63)	10.6	27,897	3.48
Total Depreciable Account 345	*2,368,096*	*1,761,683*	*770,037*					*79,917*	*3.37*
Total Account 345	2,919,753	2,313,340	770,037					79,917	2.74
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT									
Bailly - Unit 10 Regulating Station	46,151	58,336	(9,877)	50-R3	*	(5.00)	-	-	-
Bailly - Unit 10	230,444	241,966	(0)	50-R3	*	(5.00)	-	-	-
D H Mitchell - Unit 9A	24,896	26,142	0	50-R3	*	(5.00)	-	-	-
R M Schahfer - Units 18A and 16B	75,462	79,235	0	50-R3	*	(5.00)	-	-	-
R M Schahfer - Unit 16A	37,122	38,978	0	50-R3	*	(5.00)	-	-	-
R M Schahfer - Unit 16B	24,094	25,299	(0)	50-R3	*	(5.00)	-	-	-
Total Account 346	438,170	469,956	(9,877)					-	-
TOTAL GAS TURBINE PLANT	46,166,494	46,386,742	2,945,237					316,759	0.69
TRANSMISSION PLANT									
350.20 LAND RIGHTS	11,241,504	6,294,787	2,946,717	65-R4		-	39.2	75,171	0.67
352.00 STRUCTURES AND IMPROVEMENTS	14,433,696	5,604,992	9,761,333	50-R1.5		(6.46)	33.6	290,516	2.01
353.00 STATION EQUIPMENT	342,814,105	128,274,702	226,572,178	40-S0.5		(3.51)	26.2	6,724,129	2.54
354.00 TOWERS AND FIXTURES	86,317,313	68,436,446	34,177,440	60-R4		(16.19)	31.8	1,074,762	1.22
355.00 POLES AND FIXTURES	92,986,755	45,797,225	52,936,112	50-R2		(6.16)	41.6	1,272,503	1.37
356.00 OVERHEAD CONDUCTORS AND DEVICES	112,807,617	75,627,244	46,227,543	55-R2.5		(8.02)	35.8	1,291,272	1.14
357.00 UNDERGROUND CONDUIT	363,171	234,582	148,589	55-S3		-	54.0	2,752	0.72
358.00 UNDERGROUND CONDUCTORS AND DEVICES	769,396	151,624	637,772	40-R1.5		-	27.0	23,621	2.99
359.00 ROADS AND TRAILS	70,027	51,681	18,346	60-R5		-	31.6	581	0.83
TOTAL TRANSMISSION PLANT	683,843,763	330,475,283	375,428,030					12,755,307	1.92

NORTHERN INDIANA PUBLIC SERVICE COMPANY

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SNAVELY KING RECOMMENDATIONS

	DEPRECIABLE GROUP	ORIGINAL COST AT DECEMBER 31, 2007	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	ASL/ SURVIVOR CURVE	NET SALVAGE	COMPOSITE REMAINING LIFE	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE
		(1)	(2)	(3)=(1)-(2)-((1)*(5))	(4)	(5)	(6)	(7)=(3)/(6)	(8)=(7)/(1)
	DISTRIBUTION PLANT								
360.20	LAND RIGHTS	553,230	222,825	330,405	65-R4	-	33.0	10,012	1.81
361.00	STRUCTURES AND IMPROVEMENTS	11,707,553	6,086,808	5,994,218	50-R1.5	(3.19)	29.6	202,507	1.73
362.00	STATION EQUIPMENT	205,064,007	62,935,995	129,059,175	45-S0.5	(3.38)	26.0	4,609,258	2.25
	POLES, TOWERS AND FIXTURES								
364.10	Customer Transformer Station	30,196,033	17,710,658	18,821,209	45-S0.5	(20.32)	32.2	578,298	1.92
364.20	Poles, Towers, and Fixtures	224,165,558	67,148,952	190,908,006	40-R1	(24.04)	27.2	7,018,677	3.13
	Total Account 364	254,361,591	104,857,610	209,529,215				7,596,975	2.99
365.00	OVERHEAD CONDUCTORS AND DEVICES	169,246,787	127,767,430	80,468,825	50-R1.5	(11.22)	36.5	1,570,619	0.93
366.00	UNDERGROUND CONDUIT	3,646,036	1,930,399	1,715,637	60-S3	-	39.6	43,324	1.19
367.00	UNDERGROUND CONDUCTORS & DEVICES	205,520,093	71,060,167	141,673,681	50-R2.5	(3.51)	41.7	3,397,450	1.65
368.00	LINE TRANSFORMERS	195,631,364	95,599,250	100,032,114	37-R1.5	-	27.9	3,585,380	1.83
	SERVICES								
369.10	Overhead Services	37,354,317	42,365,207	(3,271,501)	45-R1.5	(4.71)	44.3	(73,849)	-0.20
369.20	Underground Services	136,032,786	97,098,205	48,552,101	50-S2.5	(7.07)	44.2	1,098,464	0.81
	Total Account 369	173,367,105	139,463,412	45,260,600				1,024,615	0.59
	METERS								
370.10	Customer Metering Stations	11,121,145	5,433,677	5,560,687	38-R2	1.14	27.0	205,951	1.85
370.20	Meters	57,896,041	20,839,318	36,379,339	32-O1	1.17	25.7	1,415,539	2.44
	Total Account 370	69,017,186	26,272,995	41,940,027				1,621,490	2.35
371.00	INSTALLATIONS ON CUSTOMER PREMISES	7,297,508	4,367,900	3,977,233	17-O1	(14.63)	13.9	286,132	3.92
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	34,364,231	26,375,814	11,129,306	30-R1	(14.96)	22.9	485,996	1.41
	TOTAL DISTRIBUTION PLANT	1,329,796,671	666,960,605	751,130,433				24,433,757	1.84
	GENERAL PLANT								
390.00	STRUCTURES AND IMPROVEMENTS	14,871,554	7,912,820	8,969,077	45-S0.5	(1.57)	31.6	236,775	1.61
	OFFICE FURNITURE AND EQUIPMENT								
391.10	Office Furniture and Equipment	5,619,066	2,583,361	3,035,707	20-SQ	-	5.9	514,527	9.16
391.20	Computers and Peripheral Equipment	34,491,085	8,362,422	26,128,663	7-SQ	-	2.0	13,064,331	37.88
	Total Account 391	40,110,153	10,945,783	29,164,370				13,578,858	33.85
393.00	STORES EQUIPMENT	1,999,776	950,711	1,049,065	30-SQ	-	8.6	121,964	6.10
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	19,883,324	10,073,534	9,809,790	25-SQ	-	7.6	1,290,782	6.49
395.00	LABORATORY EQUIPMENT	17,298,605	9,043,522	8,255,283	20-SQ	-	4.6	1,794,627	10.37
397.00	COMMUNICATION EQUIPMENT	19,198,321	7,816,813	11,361,506	15-SQ	-	6.2	1,835,727	9.56
398.00	MISCELLANEOUS EQUIPMENT	949,329	271,587	677,742	20-SQ	-	8.6	78,807	8.30
	TOTAL GENERAL PLANT	114,111,261	47,014,770	67,326,835				16,937,540	16.60
	TOTAL DEPRECIABLE PLANT	4,984,846,909	2,935,402,797	2,400,669,829				106,687,713	

NORTHERN INDIANA PUBLIC SERVICE COMPANY

ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AT DECEMBER 31, 2007
SNAVELY KING RECOMMENDATIONS

DEPRECIABLE GROUP	ORIGINAL COST AT DECEMBER 31, 2007 (1)	BOOK DEPRECIATION RESERVE (2)	FUTURE ACCRUALS (3)=(1)-(2)-((1)*(5))	ASL/ SURVIVOR CURVE (4)	NET SALVAGE (5)	COMPOSITE REMAINING LIFE (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)=(3)/(6)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(1)
							160,291,623	
*Interim survivor curves used. Each location has a unique probable retirement date.							53,604,110	
SUGAR CREEK RATES								
STEAM PLANT								
311.00 STRUCTURES AND IMPROVEMENTS	12,432,495			60	(1.55)		210,420	1.69
312.10 BOILER PLANT EQUIPMENT	114,776,675			60	(1.55)		1,942,629	1.69
314.00 TURBO-GENERATOR UNITS	3,867,643			60	(1.55)		65,460	1.69
315.00 ACCESSORY ELECTRIC EQUIPMENT	7,389,637			60	(1.55)		125,070	1.69
318.00 MISCELLANEOUS POWER PLANT EQUIPMENT	1,497,707			60	(1.55)		25,349	1.69
Total Steam	139,966,157						2,368,927	
GAS TURBINE PLANT								
341.00 STRUCTURES AND IMPROVEMENTS	718,563			40	(1.06)		18,154	2.53
342.00 FUEL HOLDERS, PRODUCTS & ACCESSORIES	2,213,632			40	(2.56)		56,771	2.56
343.00 PRIME MOVERS	8,147,608			40	(3.17)		210,153	2.58
344.00 GENERATORS	65,163			40	(1.07)		1,646	2.53
345.00 ACCESSORY ELECTRIC EQUIPMENT	814,686			40	(2.12)		20,798	2.55
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	37,122			40	(1.06)		938	2.53
Total Gas Turbine	11,996,771						308,460	
TOTAL SUGAR CREEK	151,962,928						2,677,388	

Sources:
Cols. (1), (4) and (6) from response to OUCC Set 7 DEP-31.
Col. (1) for Sugar Creek from OUCC Set 23-010 Attachment B.xls.
Col. (4) for Sugar Creek from Spanos testimony, p. 19.
Col. (2) from Schedule 5.
Col. (5) from Schedule 4 (steam) and Schedule 3 (all others).

NORTHERN INDIANA PUBLIC SERVICE COMPANY

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ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AT DECEMBER 31, 2007
SNAVELY KING RECOMMENDATIONS

	DEPRECIABLE GROUP	ORIGINAL COST AT DECEMBER 31, 2007	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	SURVIVOR CURVE	NET SALVAGE	COMPOSITE REMAINING LIFE	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE
		(1)	(2)	(3)=(1)-(2)-((1)*(5))	(4)	(5)	(6)	(7)=(3)/(6)	(8)=(7)/(1)
	COMMON PLANT								
390.00	STRUCTURES AND IMPROVEMENTS	73,386,304.34	27,107,811	47,684,388	43-S0.5	(1.92)	26.2	1,820,015	2.48
390.10	LEASEHOLD IMPROVEMENTS	2,740,911.25	2,740,911	0	20-SQ	-	-	0	-
	Total Account 390	76,127,215.59	29,848,522	47,684,366				1,820,015	2.39
	OFFICE FURNITURE AND EQUIPMENT								
391.10	Office Furniture and Equipment	26,813,139.14	10,552,707	16,260,432	20-SQ	-	2.8	5,807,297	21.66
391.20	Computers and Peripheral Equipment	17,985,557.53	(4,153,743)	22,139,301	7-SQ	-	1.8	12,299,611	68.39
	Total Account 391	44,798,696.67	6,398,964	38,399,733				16,106,909	40.42
393.00	STORES EQUIPMENT	4,124,719.96	1,359,402	2,765,318	30-SQ	-	11.5	240,462	5.83
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	11,120,765.89	997,480	10,123,286	25-SQ	-	4.8	2,109,018	18.96
395.00	LABORATORY EQUIPMENT	2,787,500.31	514,514	2,272,986	20-SQ	-	5.5	413,270	14.83
397.00	COMMUNICATION EQUIPMENT	49,694,824.86	12,989,317	36,705,508	15-SQ	-	3.0	12,235,169	24.62
398.00	MISCELLANEOUS EQUIPMENT	2,589,365.47	1,082,501	1,506,864	20-SQ	-	3.8	396,543	15.31
	TOTAL COMMON PLANT	191,243,088.75	53,190,700	139,458,081				35,321,386	18.47
	TOTAL DEPRECIABLE PLANT	191,243,088.75	53,190,700	139,458,081				35,321,386	

Sources:
Cols. (1), (2), (4) and (6) from response to OUCC Set 7 DEP-31.
Col. (5) from Schedule 3.

NORTHERN INDIANA PUBLIC SERVICE COMPANY
CALCULATION OF PRESENT VALUE NET SALVAGE

DEPRECIABLE GROUP	1984 Cost Index (1)	1/1/2008 Cost Index (2)	Compound Growth Rate (3)	Original Cost At 12/31/07 (4)	Composite Remaining Life (5)	Spanos Future Net Salvage % (6)	Spanos Future Net Salvage $ (7)=(4)*(6)	PV Future Net Salvage $ (8)	PV Future Net Salvage % (9)=(8)/(4)
STEAM PLANT									
312.30 Boiler Plant - Unit Train Coal Cars									
Depreciable									
R M Schahfer - Units 14, 15, 17 and 18	258	557	3.40%	970,020	19.9	20.00	194,004	99,736	10.28
R M Schahfer Generating Station	258	557	3.40%	242,505	19.9	20.00	46,501	24,934	10.28
Total Depreciable Account 312.30									
HYDRO PLANT									
331.00 STRUCTURES AND IMPROVEMENTS									
Norway Generating Station	221	501	3.62%	1,055,735	28.5 *	(75)	(791,801)	(287,391)	(27.22)
Norway Substation	221	501	3.62%	22,138	28.8 *	(75)	(16,603)	(5,982)	(26.93)
Oakdale Generating Station	221	501	3.62%	1,872,653	28.9 *	(75)	(1,404,489)	(502,573)	(26.84)
Oakdale Substation	221	501	3.62%	6,923	28.8 *	(75)	(5,193)	(1,865)	(26.93)
Total Account 331				2,957,449					
332.00 RESERVOIRS, DAMS AND WATERWAYS									
Norway Generating Station	217	439	3.11%	2,011,677	27.8 *	(75)	(1,508,757)	(643,958)	(32.01)
Norway Substation	217	439	3.11%	46,643	29.0 *	(75)	(35,132)	(14,454)	(30.66)
Oakdale Generating Station	217	439	3.11%	3,911,909	27.7 *	(75)	(2,933,932)	(1,256,083)	(32.11)
Total Account 332				5,970,429					
333.00 WATER WHEELS, TURBINES & GENERATORS									
Norway Generating Station	266	455	2.36%	1,540,640	26.4 *	(50)	(770,320)	(397,165)	(25.78)
Oakdale Generating Station	266	455	2.36%	2,933,102	27.8 *	(50)	(1,466,551)	(766,788)	(26.14)
Oakdale Substation	266	455	2.36%	59,723	29.2 *	(50)	(29,862)	(15,112)	(25.30)
Total Account 333				4,533,466					
334.00 ACCESSORY ELECTRIC EQUIPMENT									
Norway Generating Station	230 1/	454 1/	3.00%	1,532,673	26.0 *	(25)	(383,168)	(177,673)	(11.59)
Norway Substation	230 1/	454 1/	3.00%	24,067	23.4 *	(25)	(6,017)	(3,013)	(12.52)
Oakdale Generating Station	230 1/	454 1/	3.00%	355,846	24.6 *	(25)	(88,962)	(42,994)	(12.08)
Oakdale Substation	230 1/	454 1/	3.00%	95,866	26.2 *	(25)	(23,967)	(11,048)	(11.52)
Total Account 334				2,008,453					
335.00 MISCELLANEOUS POWER PLANT EQUIPMENT									
Norway Generating Station	230 1/	454 1/	3.00%	34,197	- *	-	-	-	-
Oakdale Generating Station	230 1/	454 1/	3.00%	58,205	- *	-	-	-	-
Total Account 335				92,402					
TOTAL HYDRO PLANT				15,562,198					

NORTHERN INDIANA PUBLIC SERVICE COMPANY
CALCULATION OF PRESENT VALUE NET SALVAGE

DEPRECIABLE GROUP	1984 Cost Index	1/1/2008 Cost Index	Compound Growth Rate	Original Cost At 12/31/07	Composite Remaining Life	Spanos Future Net Salvage %	Spanos Future Net Salvage $	PV Future Net Salvage $	PV Future Net Salvage %
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(4)*(6)	(8)	(9)=(8)/(4)
GAS TURBINE PLANT									
341.00 STRUCTURES AND IMPROVEMENTS									
Depreciable									
R M Schahfer - Units 16A and 16B	238 1/	582 1/	3.98%	840,108	12.3 *	(5)	(42,005)	(26,053)	(3.10)
R M Schahfer - Unit 16A	238 1/	582 1/	3.96%	718,563	11.8 *	(5)	(35,928)	(22,720)	(3.16)
R M Schahfer - Unit 16B	238 1/	582 1/	3.96%	169,194	11.8 *	(5)	(8,460)	(5,350)	(3.16)
Total Depreciable Account 341				*1,727,865*					
Total Account 341				2,030,542					
342.00 FUEL HOLDERS, PRODUCTS & ACCESSORIES									
Depreciable									
Bailly Generating Station	235	512	3.44%	413,347	11.5 *	(10)	(41,335)	(28,015)	(6.78)
R M Schahfer - Units 16A and 16B	235	512	3.44%	4,870,824	11.5 *	(10)	(487,082)	(330,130)	(6.78)
R M Schahfer Generating Station	235	512	3.44%	28,901	12.0 *	(10)	(2,890)	(1,926)	(6.66)
R M Schahfer - Unit 16A	235	512	3.44%	2,213,632	12.0 *	(10)	(221,363)	(147,517)	(6.66)
R M Schahfer - Unit 16B	235	512	3.44%	1,298,101	12.1 *	(10)	(129,810)	(86,214)	(6.64)
Total Depreciable Account 342				*8,824,805*					
Total Account 342				9,230,065					
343.00 PRIME MOVERS									
Depreciable									
Bailly Generating Station	238 1/	582 1/	3.96%	421,259	11.4 *	(15)	(63,189)	(40,585)	(9.63)
Bailly - Unit 10 Regulating Station	238 1/	582 1/	3.96%	207,048	11.4 *	(15)	(31,057)	(19,947)	(9.63)
Bailly - Unit 10	238 1/	582 1/	3.96%	2,549,987	11.4 *	(15)	(382,498)	(245,671)	(9.63)
R M Schahfer - Units 16A and 16B	238 1/	582 1/	3.96%	3,710,028	11.7 *	(15)	(556,504)	(353,291)	(9.52)
R M Schahfer - Unit 16A	238 1/	582 1/	3.98%	8,147,606	11.3 *	(15)	(1,222,141)	(788,011)	(9.67)
R M Schahfer - Unit 16B	238 1/	582 1/	3.96%	9,138,724	11.3 *	(15)	(1,370,509)	(883,676)	(9.67)
Total Depreciable Account 343				*24,172,649*					
Total Account 343				25,777,477					
344.00 GENERATORS									
Depreciable									
R M Schahfer Generating Station	239	581	3.94%	65,163	34.9 *	(5)	(3,258)	(846)	(1.30)
Total Account 344				5,770,487					
345.00 ACCESSORY ELECTRIC EQUIPMENT									
Depreciable									
Bailly Generating Station	238 1/	582 1/	3.96%	123,784	5.9 *	(10)	(12,378)	(9,844)	(7.95)
Bailly - Unit 10	238 1/	582 1/	3.96%	602,172	7.8 *	(10)	(60,217)	(44,827)	(7.44)
R M Schahfer - Units 16A and 16B	238 1/	582 1/	3.98%	24,933	8.3 *	(10)	(2,493)	(1,806)	(7.24)
R M Schahfer - Unit 16A	238 1/	582 1/	3.96%	814,686	10.6 *	(10)	(81,469)	(53,977)	(6.63)
R M Schahfer - Unit 16B	238 1/	582 1/	3.96%	802,521	10.6 *	(10)	(80,252)	(53,171)	(6.63)
Total Depreciable Account 345				*2,368,096*					
Total Account 345				2,919,753					

NORTHERN INDIANA PUBLIC SERVICE COMPANY
CALCULATION OF PRESENT VALUE NET SALVAGE

DEPRECIABLE GROUP	1984 Cost Index	1/1/2008 Cost Index	Compound Growth Rate	Original Cost At 12/31/07	Composite Remaining Life	Spanos Future Net Salvage %	Spanos Future Net Salvage $	PV Future Net Salvage $	PV Future Net Salvage %
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(4)*(6)	(8)	(9)=(8)/(4)
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT									
Bailly - Unit 10 Regulating Station	236 1/	582 1/	3.96%	46,151	- *	(5)	(2,308)	(2,308)	(5.00)
Bailly - Unit 10	238 1/	582 1/	3.96%	230,444	- *	(5)	(11,522)	(11,522)	(5.00)
D H Mitchell - Unit 9A	238 1/	582 1/	3.96%	24,898	- *	(5)	(1,245)	(1,245)	(5.00)
R M Schahfer - Units 16A and 16B	238 1/	582 1/	3.96%	75,462	- *	(5)	(3,773)	(3,773)	(5.00)
R M Schahfer - Unit 16A	238 1/	582 1/	3.96%	37,122	- *	(5)	(1,856)	(1,856)	(5.00)
R M Schahfer - Unit 16B	238 1/	582 1/	3.96%	24,094	- *	(5)	(1,205)	(1,205)	(5.00)
Total Account 346				438,170					
TOTAL GAS TURBINE PLANT				46,166,494					
TRANSMISSION PLANT									
350.20 LAND RIGHTS	239 1/	603 1/	4.11%	11,241,504	39.2	-	-	-	-
352.00 STRUCTURES AND IMPROVEMENTS	239 1/	603 1/	4.11%	14,433,896	33.6	(25)	(3,608,474)	(932,347)	(6.46)
353.00 STATION EQUIPMENT	241	604	4.08%	342,814,105	26.2	(10)	(34,281,410)	(12,023,637)	(3.51)
354.00 TOWERS AND FIXTURES	227	513	3.61%	88,317,313	31.8	(50)	(44,158,657)	(14,296,925)	(16.19)
355.00 POLES AND FIXTURES	234	561	3.87%	92,986,755	41.6	(30)	(27,896,027)	(5,748,478)	(6.18)
356.00 OVERHEAD CONDUCTORS AND DEVICES	268	753	4.59%	112,807,617	35.8	(40)	(45,123,047)	(9,050,042)	(8.02)
357.00 UNDERGROUND CONDUIT	223	494	3.52%	383,171	54.0	-	-	-	-
358.00 UNDERGROUND CONDUCTORS AND DEVICES	249	790	5.15%	789,396	27.0	-	-	-	-
359.00 ROADS AND TRAILS	239 1/	603 1/	4.11%	70,027	31.6	-	-	-	-
TOTAL TRANSMISSION PLANT				663,843,783					
DISTRIBUTION PLANT									
360.20 LAND RIGHTS	232 1/	563 1/	3.93%	553,230	33.0	-	-	-	-
361.00 STRUCTURES AND IMPROVEMENTS	232 1/	563 1/	3.93%	11,707,553	29.6	(10)	(1,170,755)	(374,054)	(3.19)
362.00 STATION EQUIPMENT	235	573	3.95%	205,064,007	28.0	(10)	(20,506,401)	(6,931,123)	(3.38)
POLES, TOWERS AND FIXTURES									
364.10 Customer Transformer Station	236	511	3.42%	30,196,033	32.2	(60)	(18,117,620)	(6,135,291)	(20.32)
364.20 Poles, Towers, and Fixtures	236	511	3.42%	224,165,558	27.2	(60)	(134,499,335)	(53,886,109)	(24.04)
Total Account 364				254,361,591					
365.00 OVERHEAD CONDUCTORS AND DEVICES	246	670	4.45%	169,246,767	38.5	(60)	(101,548,060)	(18,997,503)	(11.22)
366.00 UNDERGROUND CONDUIT	218	487	3.56%	3,648,036	39.6	-	-	-	-
367.00 UNDERGROUND CONDUCTORS & DEVICES	212	554	4.26%	205,520,093	41.7	(20)	(41,104,019)	(7,217,310)	(3.51)
368.00 LINE TRANSFORMERS	212	602	4.64%	195,631,364	27.9	-	-	-	-
SERVICES									
369.10 Overhead Services	224	475	3.32%	37,354,317	44.3	(20)	(7,470,863)	(1,757,932)	(4.71)
369.20 Underground Services	203	349	2.38%	136,032,788	44.2	(20)	(27,206,558)	(9,619,778)	(7.07)
Total Account 369				173,387,105					
METERS									
370.10 Customer Metering Stations	204	330	2.11%	11,121,145	27.0	2	222,423	126,572	1.14
370.20 Meters	204	330	2.11%	57,896,041	25.7	2	1,157,921	677,055	1.17
Total Account 370				69,017,186					

NORTHERN INDIANA PUBLIC SERVICE COMPANY
CALCULATION OF PRESENT VALUE NET SALVAGE

DEPRECIABLE GROUP	1984 Cost Index (1)	1/1/2008 Cost Index (2)	Compound Growth Rate (3)	Original Cost At 12/31/07 (4)	Composite Remaining Life (5)	Spanos Future Net Salvage % (6)	Spanos Future Net Salvage $ (7)=(4)*(6)	PV Future Net Salvage $ (8)	PV Future Net Salvage % (9)=(8)/(4)
371.00 INSTALLATIONS ON CUSTOMER PREMISES	232 1/	563 1/	3.93%	7,297,508	13.9	(25)	(1,824,377)	(1,067,818)	(14.63)
373.00 STREET LIGHTING AND SIGNAL SYSTEMS	273	641	3.78%	34,364,231	22.9	(35)	(12,027,481)	(5,142,469)	(14.96)
TOTAL DISTRIBUTION PLANT				1,329,798,671					
GENERAL PLANT									
390.00 STRUCTURES AND IMPROVEMENTS	241 2/	559 2/	3.73%	14,671,554	31.6	(5)	(733,578)	(230,604)	(1.57)
OFFICE FURNITURE AND EQUIPMENT									
391.10 Office Furniture and Equipment	241 2/	559 2/	3.73%	5,619,068	5.9	-	-	-	-
391.20 Computers and Peripheral Equipment	241 2/	559 2/	3.73%	34,491,085	2.0	-	-	-	-
Total Account 391				40,110,153					
393.00 STORES EQUIPMENT	241 2/	559 2/	3.73%	1,999,776	8.6	-	-	-	-
394.00 TOOLS, SHOP AND GARAGE EQUIPMENT	241 2/	559 2/	3.73%	19,883,324	7.6	-	-	-	-
395.00 LABORATORY EQUIPMENT	241 2/	559 2/	3.73%	17,298,805	4.6	-	-	-	-
397.00 COMMUNICATION EQUIPMENT	241 2/	559 2/	3.73%	19,198,321	6.2	-	-	-	-
398.00 MISCELLANEOUS EQUIPMENT	241 2/	559 2/	3.73%	949,329	8.6	-	-	-	-
TOTAL GENERAL PLANT				114,111,261					
COMMON PLANT									
390.00 STRUCTURES AND IMPROVEMENTS	241 2/	559 2/	3.73%	73,388,304	26.2	(5)	(3,669,315)	(1,405,692)	(1.92)
SUGAR CREEK - GAS TURBINE PLANT									
341.00 STRUCTURES AND IMPROVEMENTS	238 1/	582 1/	3.96%	718,583	40	(5)	(35,928)	(7,599)	(1.06)
342.00 FUEL HOLDERS, PRODUCTS & ACCESSORIES	235	512	3.44%	2,213,632	40	(10)	(221,363)	(57,222)	(2.58)
343.00 PRIME MOVERS	238 1/	582 1/	3.96%	8,147,806	40	(15)	(1,222,141)	(258,506)	(3.17)
344.00 GENERATORS	239	581	3.94%	65,163	40	(5)	(3,258)	(694)	(1.07)
345.00 ACCESSORY ELECTRIC EQUIPMENT	238 1/	582 1/	3.96%	814,686	40	(10)	(81,469)	(17,232)	(2.12)
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	238 1/	582 1/	3.96%	37,122	40	(5)	(1,856)	(393)	(1.06)

Sources:
Cols. (1) and (2) from Handy-Whitman
Cols. (4), (5) and (6) from response to OUCC Set 7 DEP-31.
Cols. (4) and (6) for Sugar Creek from OUCC Set 23-010 Attachment B.xls.
Col. (5) for Sugar Creek from Spanos testimony, p. 19.

NORTHERN INDIANA PUBLIC SERVICE COMPANY
DECOMMISSIONING COSTS RELATED TO GENERATING UNITS

UNIT	ESTIMATED RETIREMENT YEAR	TOTAL DECOMMISSIONING COSTS (CURRENT $)	SCRAP VALUE ($)	ORIGINAL COST AT 12/31/07	NET SALVAGE
(1)	(2)	(3)	(4)	(5)	(6)
STEAM					
MICHIGAN CITY					
2 and 3	2009	19,850,000	950,030	28,352,030	66.66%
12	2034	48,305,000	13,795,720	344,506,147	10.02%
TOTAL MICHIGAN CITY		68,155,000	14,745,750	372,858,177	14.32%
MITCHELL					
4	2009				
5	2009				
6	2009				
11	2009				
TOTAL MITCHELL		67,822,000	6,225,836	171,690,132	35.88%
BAILLY					
7	2023				
8	2028				
TOTAL BAILLY		47,919,000	18,539,752	442,576,155.18	6.64%
SCHAHFER					
14	2036				
15	2039				
17	2043				
18	2046				
TOTAL SCHAHFER		170,347,000	40,540,864	1,828,242,038	7.10%
GRAND TOTAL		354,243,000		2,815,366,501	**12.58%**
SUGAR CREEK		2,175,000		139,966,157	1.55%

Sources:
OUCC Set 8 DEP 36 Attachment A.xls
Sugar Creek plant balance from OUCC Set 23-010 Attachment B.xls.
Sugar Creek decommissioning amount from Ranalletta testimony, p. 12. Amount is net of salvage.

NORTHERN INDIANA PUBLIC SERVICE COMPANY

CALCULATION OF BOOK RESERVE

DEPRECIABLE GROUP	ORIGINAL COST AT DECEMBER 31, 2007 (1)	SPANOS BOOK DEPRECIATION RESERVE (2)	SK BOOK DEPRECIATION RESERVE (3)
STEAM PRODUCTION PLANT			
311.00 STRUCTURES AND IMPROVEMENTS			
Fully Depreciated			
D H Mitchell - Units 4, 5, 6 and 11	1,117,909	1,531,535	1,117,909
D H Mitchell - Units 5 and 6	5,464,682	7,486,614	5,464,662
D H Mitchell Generating Station	12,660,346	17,372,074	12,660,346
D H Mitchell - Unit 4	3,203,360	4,368,604	3,203,360
D H Mitchell - Unit 5	541,844	742,326	541,844
D H Mitchell - Unit 6	441,568	604,948	441,568
D H Mitchell - Unit 11	4,813,715	6,594,790	4,813,715
Michigan City - Units 2 and 3	476,402	805,119	476,402
Michigan City - Unit 2	42,369	71,603	42,369
Michigan City - Unit 3	9,847	16,641	9,847
Total Fully Depreciated Account 311	*28,792,041*	*39,614,254*	*28,792,041*
Depreciable			
Bailly - Units 7 and 8	22,054,618	18,360,651	18,951,392
Bailly Generating Station	12,432,495	9,821,120	10,137,108
Bailly - Unit 7	6,431,461	6,262,797	6,464,298
Bailly - Unit 8	10,957,954	9,885,196	10,203,245
Michigan City - Units 2, 3 and 12	8,034,076	11,385,471	11,751,791
Michigan City Generating Station	25,638,548	15,596,383	16,098,186
Michigan City - Unit 12	25,267,047	23,275,453	24,024,325
R M Schahfer - Units 14 and 15	9,036,085	8,751,711	6,968,943
R M Schahfer - Units 14, 15, 17 and 18	31,669,201	21,120,230	21,799,759
R M Schahfer - Units 17 and 18	56,632,982	38,590,420	39,832,041
R M Schahfer Generating Station	43,094,530	24,476,185	25,263,690
R M Schahfer - Unit 14	32,400,003	28,238,178	29,146,722
R M Schahfer - Unit 15	33,618,571	27,194,137	28,069,090
R M Schahfer - Unit 17	65,180,270	59,868,259	61,608,688
R M Schahfer - Unit 18	57,798,067	35,715,634	36,864,760
Total Depreciable Account 311	*462,465,908*	*336,361,825*	*347,184,038*
Total Account 311	491,257,948	375,976,079	375,976,079
BOILER PLANT EQUIPMENT			
312.10 Boiler Plant Equipment			
Fully Depreciated			
D H Mitchell - Units 4 and 5	1,477,244	2,023,824	1,477,244
D H Mitchell - Units 4, 5 and 6	453,563	621,381	453,563
D H Mitchell - Units 4, 5, 6 and 11	3,711,172	5,084,305	3,711,172
D H Mitchell - Units 5 and 6	1,129,049	1,546,797	1,129,049
D H Mitchell Generating Station	27,634,041	37,858,636	27,634,041
D H Mitchell - Unit 4	11,026,585	15,106,421	11,026,585
D H Mitchell - Unit 5	13,290,826	18,208,432	13,290,826
D H Mitchell - Unit 6	15,980,775	21,893,662	15,980,775
D H Mitchell - Unit 11	14,974,709	20,515,351	14,974,709
Michigan City - Units 2 and 3	9,915,400	16,757,026	9,915,400
Michigan City - Unit 2	830,226	1,403,062	830,226
Michigan City - Unit 3	337,283	570,008	337,283
Total Fully Depreciated Account 312.10	*100,760,872*	*141,588,925*	*100,760,872*

NORTHERN INDIANA PUBLIC SERVICE COMPANY

CALCULATION OF BOOK RESERVE

DEPRECIABLE GROUP	ORIGINAL COST AT DECEMBER 31, 2007 (1)	SPANOS BOOK DEPRECIATION RESERVE (2)	SK BOOK DEPRECIATION RESERVE (3)
312.10 Boiler Plant Equipment, cont.			
Depreciable			
Bailly - Units 7 and 8	31,832,911	19,765,133	20,902,504
Bailly Generating Station	114,776,675	34,934,335	36,944,607
Bailly - Unit 7	50,675,957	26,666,951	28,203,597
Bailly - Unit 8	76,652,941	51,701,428	54,878,551
Michigan City Generating Station	64,661,343	34,615,877	38,607,824
Michigan City - Unit 12	119,819,910	69,710,004	73,721,418
R M Schahfer - Units 14 and 15	22,997,865	11,203,353	11,846,042
R M Schahfer - Units 14, 15, 17 and 18	9,515,149	5,636,195	6,172,035
R M Schahfer - Units 17 and 18	44,705,449	23,317,344	24,659,124
R M Schahfer Generating Station	66,164,240	26,997,232	28,550,769
R M Schahfer - Unit 14	230,960,731	105,112,735	111,161,374
R M Schahfer - Unit 15	162,697,679	101,239,847	107,085,624
R M Schahfer - Unit 17	157,507,776	102,422,878	108,316,729
R M Schahfer - Unit 18	167,141,755	95,961,090	101,504,255
Total Depreciable Account 312.10	*1,340,532,380*	*709,506,400*	*750,334,453*
Total Account 312.10	1,441,293,251	851,095,325	851,095,325
312.20 Boiler Plant - Mobile Fuel Hdlg/Strg			
Fully Depreciated			
D H Mitchell Generating Station	2,216,917	3,037,176	2,216,917
Total Fully Depreciated Account 312.20			
Depreciable			
Bailly - Units 7 and 8	127,235	120,069	130,969
Bailly Generating Station	4,871,467	2,502,126	2,728,818
Michigan City Generating Station	3,040,053	2,428,663	2,648,697
Michigan City - Unit 12	171,112	34,849	38,006
R M Schahfer - Units 14, 15, 17 and 18	370,727	69,256	97,342
R M Schahfer Generating Station	10,131,618	3,866,035	4,019,966
R M Schahfer - Unit 15	161,951	192,724	210,185
Total Depreciable Account 312.20	*18,874,162*	*9,053,744*	*9,874,003*
Total Account 312.20	21,091,079	12,090,920	12,090,920
312.30 Boiler Plant - Unit Train Coal Cars			
Fully Depreciated			
Bailly - Units 7 and 8	2,823,046	2,258,437	2,823,046
Bailly Generating Station	17,293	13,834	17,293
Total Fully Depreciated Account 312.30	*2,840,339*	*2,272,271*	*2,840,339*
Depreciable			
R M Schahfer - Units 14, 15, 17 and 18	970,020	512,767	58,313
R M Schahfer Generating Station	242,505	128,192	14,578
Total Depreciable Account 312.30	*1,212,525*	*640,959*	*72,891*
Total Account 312.30	4,052,864	2,913,230	2,913,230
312.40 Boiler Plant - SO2 Plant Equipment			
R M Schahfer - Units 17 and 18	31,302,027	4,507,249	4,507,249
R M Schahfer Generating Station	11,014,344	1,077,555	1,077,555
R M Schahfer - Unit 17	36,326,490	8,164,702	8,164,702
R M Schahfer - Unit 18	34,823,297	6,969,394	6,969,394
Total Account 312.40	113,466,157	20,718,900	20,718,900

NORTHERN INDIANA PUBLIC SERVICE COMPANY

CALCULATION OF BOOK RESERVE

DEPRECIABLE GROUP	ORIGINAL COST AT DECEMBER 31, 2007	SPANOS BOOK DEPRECIATION RESERVE	SK BOOK DEPRECIATION RESERVE
	(1)	(2)	(3)
312.50 Boiler Plant - Coal Pile Base			
Fully Depreciated			
D H Mitchell Generating Station	2,840,862	3,891,981	2,840,862
Total Fully Depreciated Account 312.50			
Depreciable			
Bailly - Units 7 and 8	949,799	773,968	930,140
Michigan City Generating Station	664,033	709,361	852,496
R M Schahfer - Units 14 and 15	1,629,921	1,740,963	2,092,256
R M Schahfer - Units 17 and 18	2,400,176	1,984,917	2,385,435
Total Depreciable Account 312.50	*5,843,930*	*5,209,209*	*6,260,328*
Total Account 312.50	8,884,792	9,101,190	9,101,190
Total Account 312	1,588,588,144	895,919,565	895,919,565
314.00 TURBO-GENERATOR UNITS			
Fully Depreciated			
D H Mitchell - Units 4 and 5	62,957	86,251	62,957
D H Mitchell - Units 4, 5, 6 and 11	72,506	99,334	72,506
D H Mitchell - Units 5 and 6	520,326	712,846	520,326
D H Mitchell Generating Station	4,081,504	5,591,660	4,081,504
D H Mitchell - Unit 4	6,956,893	9,530,943	6,956,893
D H Mitchell - Unit 5	8,643,575	11,841,698	8,643,575
D H Mitchell - Unit 6	3,364,430	4,609,269	3,364,430
D H Mitchell - Unit 11	5,183,599	7,101,530	5,183,599
Michigan City - Units 2 and 3	1,196,747	2,025,882	1,198,747
Michigan City - Unit 2	2,403,348	4,061,658	2,403,348
Michigan City - Unit 3	2,298,372	3,884,249	2,298,372
Total Fully Depreciated Account 314	*34,786,257*	*49,545,320*	*34,786,257*
Depreciable			
Bailly - Units 7 and 8	2,657,603	2,564,406	2,706,581
Bailly Generating Station	3,867,643	1,704,691	1,799,202
Bailly - Unit 7	36,770,929	22,549,632	23,799,820
Bailly - Unit 8	22,000,737	16,796,848	17,728,092
Michigan City Generating Station	2,825,582	2,312,245	2,440,440
Michigan City - Unit 12	40,636,660	34,861,104	36,793,860
R M Schahfer - Units 14 and 15	1,104,031	717,798	757,594
R M Schahfer - Units 14 and 17	89,017	26,848	28,336
R M Schahfer - Units 14, 15, 17 and 18	1,096,193	766,935	809,455
R M Schahfer - Units 14, 17 and 18	115,758	37,047	39,101
R M Schahfer - Units 15 and 18	65,912	25,071	26,461
R M Schahfer - Units 17 and 18	1,862,078	743,381	784,595
R M Schahfer Generating Station	4,515,636	2,492,764	2,630,967
R M Schahfer - Unit 14	45,150,042	32,991,379	34,820,474
R M Schahfer - Unit 15	53,083,407	36,151,366	38,155,656
R M Schahfer - Unit 17	63,677,474	56,382,557	59,508,497
R M Schahfer - Unit 18	88,174,481	55,085,077	58,139,082
Total Depreciable Account 314	*367,693,160*	*266,209,149*	*260,968,212*
Total Account 314	422,479,417	315,754,469	315,754,469

NORTHERN INDIANA PUBLIC SERVICE COMPANY

CALCULATION OF BOOK RESERVE

DEPRECIABLE GROUP	ORIGINAL COST AT DECEMBER 31, 2007 (1)	SPANOS BOOK DEPRECIATION RESERVE (2)	SK BOOK DEPRECIATION RESERVE (3)
315.00 ACCESSORY ELECTRIC EQUIPMENT			
Fully Depreciated			
D H Mitchell - Units 4 and 5	3,406	4,666	3,406
D H Mitchell - Units 4, 5 and 6	23,450	32,126	23,450
D H Mitchell - Units 4, 5, 6 and 11	113,519	155,521	113,519
D H Mitchell - Units 5 and 6	2,223,011	3,045,525	2,223,011
D H Mitchell Generating Station	7,240,293	9,919,202	7,240,293
D H Mitchell - Unit 4	2,049,205	2,807,411	2,049,205
D H Mitchell - Unit 5	815,536	1,117,284	815,538
D H Mitchell - Unit 6	907,664	1,243,774	907,884
D H Mitchell - Unit 11	4,304,167	5,896,736	4,304,187
Michigan City - Units 2 and 3	1,359,508	2,297,589	1,359,508
Michigan City - Unit 2	194,267	328,311	194,287
Michigan City - Unit 3	57,845	97,758	57,845
Total Fully Depreciated Account 315	*19,292,091*	*26,945,883*	*19,292,091*
Depreciable			
Beilly - Units 7 and 8	2,979,569	1,754,826	1,831,728
Bailly Generating Station	7,389,637	2,823,387	2,947,095
Bailly - Unit 7	10,182,902	8,995,477	9,389,688
Bailly - Unit 8	16,563,650	11,674,206	12,185,805
Michigan City Generating Station	18,685,626	9,882,257	10,315,327
Michigan City - Unit 12	16,289,334	15,277,006	15,948,490
R M Schahfer - Units 14 and 15	3,109,668	1,868,935	1,950,837
R M Schahfer - Units 14, 15, 17 and 18	3,278,235	1,631,910	1,703,425
R M Schahfer - Units 17 and 18	34,020,687	23,091,585	24,103,527
R M Schahfer Generating Station	27,187,536	18,218,875	19,017,280
R M Schehfer - Unit 14	22,673,364	18,039,810	18,830,180
R M Schahfer - Unit 15	21,060,106	14,739,987	15,385,937
R M Schehfer - Unit 17	37,997,042	28,892,910	27,882,873
R M Schahfer - Unit 18	31,433,207	19,961,498	20,836,270
Total Depreciable Account 315	*255,030,562*	*174,652,449*	*182,306,241*
Total Account 315	274,322,653	201,598,332	201,598,332
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT			
Fully Depreciated			
D H Mitchell - Units 4, 5, 6 and 11	1,269,835	1,739,674	1,269,835
D H Mitchell - Units 5 and 6	29,770	40,785	29,770
D H Mitchell Generating Station	513,457	703,436	513,457
D H Mitchell - Unit 4	78,129	104,297	78,129
D H Mitchell - Unit 5	20,758	28,438	20,758
D H Mitchell - Unit 6	19,891	27,251	19,891
D H Mitchell - Unit 11	194,865	268,968	194,885
Michigan City - Units 2 and 3	114,088	192,808	114,088
Total Fully Depreciated Account 316	*2,238,793*	*3,103,655*	*2,238,793*

NORTHERN INDIANA PUBLIC SERVICE COMPANY

CALCULATION OF BOOK RESERVE

DEPRECIABLE GROUP	ORIGINAL COST AT DECEMBER 31, 2007	SPANOS BOOK DEPRECIATION RESERVE	SK BOOK DEPRECIATION RESERVE
	(1)	(2)	(3)
Depreciable			
Bailly - Units 7 and 8	2,950,691	1,676,966	1,734,752
Bailly Generating Station	1,497,707	915,422	945,827
Bailly - Unit 7	269,755	196,740	203,275
Bailly - Unit 8	639,482	476,410	492,233
Michigan City - Units 2, 3 and 12	1,080,253	961,798	993,743
Michigan City Generating Station	1,631,912	1,373,239	1,418,850
Michigan City - Unit 12	2,774,987	2,264,236	2,339,440
R M Schahfer - Units 14 and 15	669,431	463,471	476,865
R M Schahfer - Units 14, 15, 17 and 18	9,296,634	6,727,163	8,950,598
R M Schahfer - Units 17 and 18	1,614,481	746,865	771,871
R M Schahfer Generating Station	1,204,364	562,495	581,178
R M Schahfer - Unit 14	2,497,567	2,259,747	2,334,802
R M Schahfer - Unit 15	2,672,588	2,162,999	2,234,841
R M Schahfer - Unit 17	3,562,435	2,716,380	2,606,802
R M Schahfer - Unit 18	3,917,262	2,533,190	2,617,327
Total Depreciable Account 316	*36,479,546*	*26,039,141*	*26,904,003*
Total Account 316	36,718,339	29,142,796	29,142,796
TOTAL STEAM PRODUCTION PLANT	2,815,386,501	1,616,391,241	1,816,391,241
HYDRO PLANT			
331.00 STRUCTURES AND IMPROVEMENTS			
Norway Generating Station	1,055,735	184,980	184,980
Norway Substation	22,138	5,597	5,597
Oakdale Generating Station	1,672,653	294,861	294,861
Oakdale Substation	6,923	1,751	1,751
Total Account 331	2,957,449	487,189	487,189
332.00 RESERVOIRS, DAMS AND WATERWAYS			
Norway Generating Station	2,011,677	136,621	136,621
Norway Substation	48,843	3,285	3,285
Oakdale Generating Station	3,911,909	249,691	249,691
Total Account 332	5,970,429	369,597	369,597
333.00 WATER WHEELS, TURBINES & GENERATORS			
Norway Generating Station	1,540,840	747,623	747,623
Oakdale Generating Station	2,933,102	1,797,436	1,797,436
Oakdale Substation	59,723	7,362	7,362
Total Account 333	4,533,466	2,552,421	2,552,421
334.00 ACCESSORY ELECTRIC EQUIPMENT			
Norway Generating Station	1,532,673	419,442	419,442
Norway Substation	24,067	10,670	10,670
Oakdale Generating Station	355,846	125,480	125,480
Oakdale Substation	95,866	25,107	25,107
Total Account 334	2,008,453	580,699	580,699
335.00 MISCELLANEOUS POWER PLANT EQUIPMENT			
Norway Generating Station	34,197	34,197	34,197
Oakdale Generating Station	56,205	110,053	110,053
Total Account 335	92,402	144,250	144,250
TOTAL HYDRO PLANT	15,562,198	4,154,156	4,154,156

NORTHERN INDIANA PUBLIC SERVICE COMPANY

CALCULATION OF BOOK RESERVE

DEPRECIABLE GROUP	ORIGINAL COST AT DECEMBER 31, 2007	SPANOS BOOK DEPRECIATION RESERVE	SK BOOK DEPRECIATION RESERVE
	(1)	(2)	(3)
GAS TURBINE PLANT			
341.00 STRUCTURES AND IMPROVEMENTS			
Fully Depreciated			
Bailly - Unit 10	209,096	219,551	209,096
D H Mitchell - Unit 9A	93,581	98,260	93,581
Total Fully Depreciated Account 341	*302,677*	*317,811*	*302,677*
Depreciable			
R M Schahfer - Units 16A and 16B	840,108	794,664	801,869
R M Schahfer - Unit 16A	718,563	749,436	756,045
R M Schahfer - Unit 16B	169,194	172,656	174,178
Total Depreciable Account 341	*1,727,865*	*1,716,758*	*1,731,892*
Total Account 341	2,030,542	2,034,569	2,034,569
342.00 FUEL HOLDERS, PRODUCTS & ACCESSORIES			
Fully Depreciated			
Bailly - Unit 10	43,439	47,763	43,439
D H Mitchell - Unit 9A	314,702	346,172	314,702
D H Mitchell Generating Station	47,120	51,631	47,120
Total Fully Depreciated Account 342	*405,260*	*445,786*	*405,280*
Depreciable			
Bailly Generating Station	413,347	432,300	434,240
R M Schahfer - Units 16A and 16B	4,870,824	5,138,436	5,161,500
R M Schahfer Generating Station	28,901	28,025	28,151
R M Schahfer - Unit 16A	2,213,632	2,193,684	2,203,530
R M Schahfer - Unit 18B	1,298,101	1,236,473	1,242,023
Total Depreciable Account 342	*8,824,805*	*9,028,918*	*9,069,444*
Total Account 342	9,230,065	9,474,704	9,474,704
343.00 PRIME MOVERS			
Fully Depreciated			
D H Mitchell Generating Station	4,464	5,134	4,464
D H Mitchell - Unit 9A	1,600,364	1,840,419	1,600,364
Total Fully Depreciated Account 343	*1,604,828*	*1,845,553*	*1,604,828*
Depreciable			
Bailly Generating Station	421,259	181,067	182,868
Bailly - Unit 10 Regulating Station	207,048	86,279	87,146
Bailly - Unit 10	2,549,987	2,395,620	2,419,891
R M Schahfer - Units 16A and 16B	3,710,026	3,532,217	3,567,706
R M Schahfer - Unit 16A	6,147,606	8,392,421	8,476,741
R M Schahfer - Unit 16B	9,136,724	9,371,681	9,465,840
Total Depreciable Account 343	*24,172,649*	*23,959,485*	*24,200,210*
Total Account 343	25,777,477	25,805,038	25,805,038
344.00 GENERATORS			
Fully Depreciated			
Bailly - Unit 10 Regulating Station	28,231	326,360	28,231
Bailly - Unit 10	542,631	569,762	542,631
D H Mitchell - Unit 9A	382,847	380,989	382,847
R M Schahfer - Unit 16A	2,385,808	2,505,098	2,385,808
R M Schahfer - Unit 16B	2,385,808	2,505,098	2,385,808
Total Fully Depreciated Account 344	*5,705,324*	*6,287,307*	*5,705,324*

NORTHERN INDIANA PUBLIC SERVICE COMPANY

CALCULATION OF BOOK RESERVE

DEPRECIABLE GROUP	ORIGINAL COST AT DECEMBER 31, 2007	SPANOS BOOK DEPRECIATION RESERVE	SK BOOK DEPRECIATION RESERVE
	(1)	(2)	(3)
Depreciable			
R M Schahfer Generating Station	85,163	1,828	583,811
Total Account 344	5,770,487	6,289,135	6,289,135
345.00 ACCESSORY ELECTRIC EQUIPMENT			
Fully Depreciated			
O H Mitchall - Unit 9A	532,231	585,454	532,231
O H Mitchall Generating Station	19,426	21,368	19,428
Total Fully Dapreciated Account 345	*551,657*	*606,822*	*551,657*
Depreciable			
Bailly Generating Station	123,784	109,098	112,625
Bailly - Unit 10	602,172	482,524	496,122
R M Schahfar - Units 16A and 16B	24,933	20,348	21,006
R M Schahfar - Unit 16A	814,666	552,103	569,950
R M Schahfer - Unit 16B	802,521	542,445	559,980
Total Dapreciable Account 345	*2,368,096*	*1,706,518*	*1,761,683*
Total Account 345	2,919,753	2,313,340	2,313,340
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT			
Bailly - Unit 10 Regulating Station	46,151	58,336	58,336
Bailly - Unit 10	230,444	241,966	241,966
D H Mitchell - Unit 9A	24,898	26,142	26,142
R M Schahfer - Units 16A and 16B	75,462	79,235	79,235
R M Schahfer - Unit 16A	37,122	38,978	38,978
R M Schahfer - Unit 16B	24,094	25,299	25,299
Total Account 346	438,170	469,958	469,956
TOTAL GAS TURBINE PLANT	48,166,494	46,386,742	46,386,742
TRANSMISSION PLANT			
350.20 LAND RIGHTS	11,241,504	8,294,787	8,294,787
352.00 STRUCTURES AND IMPROVEMENTS	14,433,896	5,604,992	5,604,992
353.00 STATION EQUIPMENT	342,814,105	126,274,702	126,274,702
354.00 TOWERS AND FIXTURES	88,317,313	68,438,446	68,438,446
355.00 POLES AND FIXTURES	92,986,755	45,797,225	45,797,225
356.00 OVERHEAD CONDUCTORS AND DEVICES	112,807,617	75,627,244	75,627,244
357.00 UNDERGROUND CONDUIT	383,171	234,582	234,582
358.00 UNDERGROUND CONDUCTORS AND DEVICES	789,396	151,824	151,624
359.00 ROADS AND TRAILS	70,027	51,661	51,681
TOTAL TRANSMISSION PLANT	663,843,783	330,475,283	330,475,283
DISTRIBUTION PLANT			
360.20 LAND RIGHTS	553,230	222,625	222,825
361.00 STRUCTURES AND IMPROVEMENTS	11,707,553	6,066,606	6,086,808
362.00 STATION EQUIPMENT	205,084,007	82,935,995	82,935,995
POLES, TOWERS AND FIXTURES			
364.10 Customer Transformer Station	30,196,033	17,710,656	17,710,658
364.20 Poles, Towars, and Fixtures	224,165,558	87,146,952	67,146,952
Total Account 364	254,361,591	104,657,610	104,857,610
365.00 OVERHEAD CONDUCTORS AND DEVICES	169,246,767	127,767,430	127,767,430
366.00 UNDERGROUND CONDUIT	3,646,036	1,930,399	1,930,399
367.00 UNDERGROUND CONDUCTORS & DEVICES	205,520,093	71,060,167	71,060,167
368.00 LINE TRANSFORMERS	195,831,364	95,599,250	95,599,250

NORTHERN INDIANA PUBLIC SERVICE COMPANY

CALCULATION OF BOOK RESERVE

	DEPRECIABLE GROUP	ORIGINAL COST AT DECEMBER 31, 2007	SPANOS BOOK DEPRECIATION RESERVE	SK BOOK DEPRECIATION RESERVE
		(1)	(2)	(3)
	SERVICES			
369.10	Overhead Services	37,354,317	42,385,207	42,385,207
369.20	Underground Services	136,032,788	97,098,205	97,098,205
	Total Account 369	173,387,105	139,483,412	139,483,412
	METERS			
370.10	Customer Metering Stations	11,121,145	5,433,677	5,433,677
370.20	Meters	57,896,041	20,839,318	20,839,318
	Total Account 370	69,017,186	26,272,995	26,272,995
371.00	INSTALLATIONS ON CUSTOMER PREMISES	7,297,508	4,387,900	4,387,900
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	34,364,231	28,375,814	26,375,814
	TOTAL DISTRIBUTION PLANT	1,329,798,871	888,980,605	888,980,605
	GENERAL PLANT			
390.00	STRUCTURES AND IMPROVEMENTS	14,671,554	7,912,820	7,912,820
	OFFICE FURNITURE AND EQUIPMENT			
391.10	Office Furniture and Equipment	5,819,068	2,583,361	2,583,361
391.20	Computers and Peripheral Equipment	34,491,085	8,362,422	8,362,422
	Total Account 391	40,110,153	10,945,783	10,945,783
393.00	STORES EQUIPMENT	1,999,778	950,711	950,711
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	19,883,324	10,073,534	10,073,534
395.00	LABORATORY EQUIPMENT	17,298,805	9,043,522	9,043,522
397.00	COMMUNICATION EQUIPMENT	19,198,321	7,816,813	7,816,813
398.00	MISCELLANEOUS EQUIPMENT	949,329	271,567	271,567
	TOTAL GENERAL PLANT	114,111,261	47,014,770	47,014,770
	TOTAL DEPRECIABLE PLANT	4,984,846,909	2,935,402,797	2,935,402,797

Sources.
Cols. (1) and (2) from response to OUCC Set 7 DEP-31.
Col. (3) for fully depreciated set equal to original cost. Remaining reserve by account allocated to depreciable plant based on Spanos allocation.

Northern Indiana Public Service Company
Pro Forma Adjustment to Depreciation and Amortization Expense
Twelve Months Ended December 31, 2007
Adjustment DA-2

This pro forma adjustment increased 2007 test year depreciation and amortization expense to reflect the expense amount calculated using new depreciation rates per the depreciation study.

Line No.	Description	NIPSCO Amount	OUCC Amount	Difference
	A	B	C	D=C-B
1	2007 Actual Depreciation Expense	$ 178,244,660	$ 176,244,680	$ -
2	D&A Study Depreciation Expense	$ 185,828,320	$ 131,988,053	$ (53,840,267)
3	Sugar Creek Depreciation Expense	$ 11,236,857	$ 7,065,613	$ (4,171,244)
4	Total Depreciation - New Rates and Sugar Creek	$ 197,065,177	$ 139,053,666	$ (58,011,511)
5	**Change in Pro Forma Test Year Depreciation and Amortization Expense**	**$ 20,820,517**	**$ (37,190,994)**	**$ (58,011,511)**

Sources:
Col. B from Petitioner's Exhibit LEM-3(Revised), Adjustment DA-2
Col. C calculated using workpapers provided in response OUCC Set 7 DEP-016 and Snavely King recommended depreciation rates.

Northern Indiana Public Service Company
Pro Forma Adjustment to Depreciation and Amortization Expense
Twelve Months Ended December 31, 2007
Adjustment SCDA-7

This pro forma adjustment increased 2007 test year depreciation and amortization expense to amortize costs of deferred depreciation on Sugar Creek per Cause No. 43396.

Line No.	Description	NIPSCO Amount	OUCC Amount	Difference
	A	B	C	D=C-B
1	Annual Depreciation	$ 11,236,857	$ 7,065,613	$ (4,171,244)
2	Annual Reduction (FAC71-S1)	$ 4,500,000	$ 4,500,000	$ -
3	Annual Depreciation Deferred	$ 6,736,857	$ 2,565,613	$ (4,171,244)
4	Months (December 1, 2008 through December 31, 2009)	13	$ 13	
5	Total Depreciation Deferred (Line 3 divided by 12, multiplied by 13)	$ 7,298,262	$ 2,779,414	$ (4,518,846)
6	Amortization Period in Years per Cause No. 43396	5	5	
7	Change in Pro Forma Test Year Depreciation and Amortization Expense	$ 1,459,652	$ 555,883	$ (903,770)

Sources:
Col. B from Petitioner's Exhibit LEM-3(Revised), Adjustment SCDA-7.
Col. C, line 1 calculated using workpapers provided in response OUCC Set 7 DEP-016 and Snavely King recommended depreciation rates.

Calculation of Pro Forma Depreciation and Amortization Expense - Electric Plant
Twelve Months Ended December 31, 2007

Line No.	A/C	Description	Plant In Service A/C 101 & 106	SK Recommended Rates	Pro Forma D&A Expense
	A	B	C	D	E =CxD
1		INTANGIBLE PLANT			
2	300		$ -	0.00%	$ -
3	301	ORGANIZATION	$ -	0.00%	$ -
4	302	FRANCHISES & CONSENTS	$ 1,389	0.00%	$ -
5	303	MISC INTANGIBLE PLANT	$ 26,430,151	0.00%	$ -
6		TOTAL INTANG PLANT	$ 26,431,540		$ -
7		STEAM PRODUCTION PLANT			
8	310	LAND AND LAND RIGHTS	$ 3,872,128	0.00%	$ -
9	311	STRUCTS & IMPRVMNTS	$ 462,465,907	1.03%	$ 4,763,399
10	312.10	BOILER PLANT EQP	$ 1,340,532,380	2.30%	$ 30,832,245
11	312.20	MOBILE FUEL HDLG/STRG	$ 18,874,162	2.12%	$ 400,132
12	312.30	UNIT TRAIN COAL CARS	$ 4,052,864	4.21%	$ 170,626
13	312.40	S02 PLANT EQP	$ 113,466,159	3.06%	$ 3,472,064
14	312.50	COAL PILE BASE	$ 5,843,930	0.00%	$ -
15	313	ENGS & ENG-DRVN GENS	$ -	0.00%	$ -
16	314	TURBOGENERATOR UNITS	$ 387,693,160	1.53%	$ 5,931,705
17	315	ACCESSORY ELECTRIC EQP	$ 255,030,560	1.48%	$ 3,774,452
18	316	MISC PWR PLNT EQP	$ 36,479,546	1.34%	$ 488,826
19		TOAL STEAM PROD PLANT	$ 2,628,310,796		$ 49,833,449
20		NUCLEAR PROD PLANT			
21	321	STRUCTS & IMPRVMNTS	$ -	0.00%	$ -
22		TOTAL NUC PROD PLANT	$ -		$ -
23		HYDRO PROD PLANT			
24	330	LAND AND LAND RIGHTS	$ 23,137	0.00%	$ -
25	331	STRUCTS & IMPRVMNTS	$ 2,957,448	3.84%	$ 113,566
26	332	RESIVRS, DAMS, WTR WAYS	$ 5,970,428	4.53%	$ 270,460
27	333	WTR WHLS, TURBNS, GENS	$ 4,533,466	2.48%	$ 112,430
28	334	ACCESSORY ELECTRIC EQP	$ 2,008,452	3.22%	$ 64,672
29	335	MISC PWR PLNT EQP	$ 92,403	0.00%	$ -
30	336	ROADS, RRS, AND BRIDGES	$ -	0.00%	$ -
31		TOTAL HYDRO PROD PLNT	$ 15,585,334		$ 561,129
32		OTH PROD PLANT			
33	340	LAND AND LAND RIGHTS	$ 8,727	0.00%	$ -
34	341	STRUCTS & IMPRVMNTS	$ 1,936,962	0.23%	$ 4,455
35	342	FL HLDRS, PRDCTS, & ACS	$ 8,868,244	0.33%	$ 29,265
36	343	PRIME MOVERS	$ 24,172,649	0.83%	$ 200,633
37	344	GENERATORS	$ 5,407,640	2.93%	$ 158,444
38	345	ACCSRY ELECT EQP	$ 2,368,096	3.37%	$ 79,805
39	346	MISC PWR PLNT EQP	$ 413,272	0.00%	$ -
40		TOT OTH PROD PLANT	$ 43,175,590		$ 472,602
41		TOTAL PROD PLANT	$ 2,687,071,720		$ 50,867,180

Calculation of Pro Forma Depreciation and Amortization Expense - Electric Plant
Twelve Months Ended December 31, 2007

Line No.	A/C	Description	Plant In Service A/C 101 & 106	SK Recommended Rates	Pro Forma D&A Expense
	A	B	C	D	E =CxD
42		TRANSMISSION PLANT			
43	350.10	LAND	$ 16,587,135	0.00%	$ -
44	350.20	LAND RIGHTS	$ 11,218,867	0.67%	$ 75,166
45	352	STRUCTS & IMPRVMNTS	$ 14,433,871	2.01%	$ 290,121
46	353	STATION EQP	$ 342,709,598	2.54%	$ 8,704,824
47	354	TOWERS AND FIXTURES	$ 88,317,314	1.22%	$ 1,077,471
48	355	POLES AND FIXTURES	$ 92,986,757	1.37%	$ 1,273,919
49	356	OVHD CNDCTRS AND DEV	$ 112,807,613	1.14%	$ 1,286,007
50	357	UDGRND CONDUIT	$ 383,172	0.72%	$ 2,759
51	358	UDGRND CNDCTRS & DEV	$ 789,393	2.99%	$ 23,603
52	359	ROADS AND TRAILS	$ 70,027	0.83%	$ 581
53		TOTAL TRANSM PLANT	$ 680,303,747		$ 12,734,451
54		DISTRIBUTION PLANT			
55	360.10	LAND	$ 2,256,315	0.00%	$ -
56	360.20	LAND RIGHTS	$ 553,229	1.81%	$ 10,013
57	361	STRUCTS & IMPRVMNTS	$ 11,707,553	1.73%	$ 202,541
58	362	STATION EQP	$ 205,064,005	2.25%	$ 4,613,940
59	363	STORAGE BATTERY EQP	$ -	0.00%	$ -
60	364	POLES, TWRS, AND FXTRS	$ 254,410,393	2.99%	$ 7,606,871
61	365	OVHD CNDCTRS AND DEV	$ 169,246,765	0.93%	$ 1,573,995
62	366	UGRND CONDUIT	$ 3,646,037	1.19%	$ 43,388
63	367	UGRND CNDCTRS & DEV	$ 205,520,096	1.65%	$ 3,391,082
64	368	LINE TRANSFORMERS	$ 195,631,363	1.83%	$ 3,580,054
65	369	SERVICES	$ 173,387,109	0.59%	$ 1,022,984
66	370	METERS	$ 69,017,188	2.35%	$ 1,621,904
67	371	INSTLTS ON CUST PREM	$ 7,297,506	3.92%	$ 286,062
68	372	LSD PROP ON CUST PREM	$ -	0.00%	$ -
89	373	STRT LGHTS & SGNL SYS	$ 34,364,231	1.41%	$ 484,536
70		TOTAL DISTRIB PLANT	$ 1,332,101,790		$ 24,437,369
71		GENERAL PLANT			
72	389	LAND AND LAND RIGHTS	$ 200,133	0.00%	$ -
73	390	STRUCTS & IMPRVMNTS	$ 14,671,552	1.61%	$ 236,212
74	391	OFC FURN & EQP	$ 40,110,153	33.85%	$ 13,577,287
75	392	TRANSPORTATION EQP	$ 8,440,316	0.00%	$ -
76	393	STORES EQUIPMENT	$ 1,999,775	6.10%	$ 121,986
77	394	TOOLS, SHP, & GRG EQP	$ 19,878,594	6.49%	$ 1,290,121
78	395	LAB EQUIPMENT	$ 17,298,797	10.37%	$ 1,793,885
79	396	PWR OPERATED EQP	$ 28,858,146	0.00%	$ -
80	397	COMMUNICATION EQUIP	$ 19,198,321	9.56%	$ 1,835,359
81	398	MISC EQP	$ 949,329	8.30%	$ 78,794
82		TOTAL GENERAL PLANT	$ 151,605,116		$ 18,933,645
83					
86		TOTAL PLANT IN SERVICE	$ 4,877,513,913		$ 106,972,844

Sources:
Cols. A&C from OUCC Set 7 DEP 16, Attachment A. Col. B from Schedule 1.

Calculation of Pro Forma Depreciation and Amortization Expense - Common Plant
Twelve Months Ended December 31, 2007

Line No.	A/C	Description	Plant In Service A/C 101 & 106	SK Recommended Rates	Pro Forma D&A Expense
	A	B	C	D	E
					=CxD
1		INTANGIBLE PLANT			
2	301	ORGANIZATION	$ 90,403	0.00%	$ -
3	303	MISC INTANGIBLE PLANT	$ 63,185,925	0.00%	$ -
4		TOT INTANGIBLE PLANT	$ 63,276,328		$ -
5		GENERAL PLANT			
6	389	LAND AND LAND RGHTS	$ 6,740,942	0.00%	$ -
7	390	STRUCTURES & IMPROV	$ 54,212,920	2.39%	$ 1,295,689
8	391	OFFICE FURNITURE & EQP	$ 31,544,291	40.42%	$ 12,750,202
9	392	AUTOS	$ 5,401,004	0.00%	$ -
10	393	STORES EQUIPMENT	$ 2,939,276	5.83%	$ 171,360
11	394	TOOLS / GARAGE EQUIP	$ 7,924,664	18.96%	$ 1,502,516
12	395	LABORATORY EQUIPMENT	$ 1,986,373	14.83%	$ 294,579
13	396	POWER OPERATED EQUIP	$ 3,219,030	0.00%	$ -
14	397	COMMUNICATION EQUIP	$ 35,412,532	24.62%	$ 8,718,565
15	398	MISC. EQUIPMENT	$ 1,845,182	15.31%	$ 282,497
16		TOTAL GENERAL PLANT	$ 151,226,214		$ 25,015,409
17					
18		TOTAL PLANT IN SERVICE	$ 214,502,542		$ 25,015,409

Sources:
Cols. A&C from OUCC Set 7 DEP 16, Attachment A
Col. B from Schedule 2.

Calculation of Pro Forma Depreciation and Amortization Expense - Sugar Creek
Twelve Months Ended December 31, 2007

Line No.	A/C	Description	Plant In Service A/C 101 & 106	SK Recommended Rates	Pro Forma D&A Expense
	A	B	C	D	E
1		INTANGIBLE PLANT			
2	300	???	$ -		$ -
3	301	ORGANIZATION	$ -		$ -
4	302	FRANCHISES & CONSENTS	$ -		$ -
5	303	MISC INTANGIBLE PLANT	$ -		$ -
6		TOTAL INTANG PLANT	$ -		$ -
7		STEAM PRODUCTION PLANT	$ -		
8	310	LAND AND LAND RIGHTS	$ -		$ -
9	311	STRUCTS & IMPRVMNTS	$ 4,455,333	1.69%	75,295
10	312	BOILER PLANT EQP	$ 84,341,737	1.69%	1,425,375
11	313	ENGS & ENG-DRVN GENS	$ -	0.00%	-
12	314	TURBOGENERATOR UNITS	$ 55,831,809	1.69%	943,558
13	315	ACCESSORY ELECTRIC EQP	$ 3,906,698	1.69%	66,023
14	316	MISC PWR PLNT EQP	$ -		-
15		TOAL STEAM PROD PLANT	$ 148,535,577		2,510,251
16		NUCLEAR PROD PLANT	$ -		
17	321	STRUCTS & IMPRVMNTS	$ -		$ -
18		TOTAL NUC PROD PLANT	$ -		$ -
19		HYDRO PROD PLANT	$ -		
20	330	LAND AND LAND RIGHTS	$ -		$ -
21	331	STRUCTS & IMPRVMNTS	$ -		$ -
22	332	RESIVRS, DAMS, WTR WAYS	$ -		$ -
23	333	WTR WHLS, TURBNS, GENS	$ -		$ -
24	334	ACCESSORY ELECTRIC EQP	$ -		$ -
25	335	MISC PWR PLNT EQP	$ -		$ -
26	336	ROADS, RRS, AND BRIDGES	$ -		$ -
27		TOTAL HYDRO PROD PLNT	$ -		$ -
28		OTH PROD PLANT	$ -		
29	340	LAND AND LAND RIGHTS	$ 1,095,678	0.00%	$ -
30	341	STRUCTS & IMPRVMNTS	$ 14,972,251	2.53%	378,798
31	342	FL HLDRS, PRDCTS, & ACS	$ 8,083,812	2.56%	206,946
32	343	PRIME MOVERS	$ 73,982,005	2.58%	1,908,736
33	344	GENERATORS	$ 27,307,708	2.53%	690,885
34	345	ACCSRY ELECT EQP	$ 31,712,497	2.55%	808,669
35	346	MISC PWR PLNT EQP	$ 7,374,323	2.53%	186,570
36		TOT OTH PROD PLANT	$ 164,528,274		$ 4,180,603
37		TOTAL PROD PLANT	$ 313,063,851		$ 6,690,855

Calculation of Pro Forma Depreciation and Amortization Expense - Sugar Creek
Twelve Months Ended December 31, 2007

Line No.	A/C	Description	Plant In Service A/C 101 & 106	SK Recommended Rates	Pro Forma D&A Expense
	A	B	C	D	E
38		TRANSMISSION PLANT	$ -		
39	350	LAND AND LAND RIGHTS	$ -		$ -
40	352	STRUCTS & IMPRVMNTS	$ -	0.00%	$ -
41	353	STATION EQP	$ 14,616,474	2.48%	$ 362,489
42	354	TOWERS AND FIXTURES	$ -	0.00%	$ -
43	355	POLES AND FIXTURES	$ -	0.00%	$ -
44	356	OVHD CNDCTRS AND DEV	$ -	0.00%	$ -
45	357	UDGRND CONDUIT	$ -	0.00%	$ -
46	358	UDGRND CNDCTRS & DEV	$ -	0.00%	$ -
47	359	ROADS AND TRAILS	$ -	0.00%	$ -
48		TOTAL TRANSM PLANT	$ 14,616,474		$ 362,489
49		GENERAL PLANT	$ -		
50	389	LAND AND LAND RIGHTS	$ -	0.00%	$ -
51	390	STRUCTS & IMPRVMNTS	$ -	0.00%	$ -
52	391	OFC FURN & EQP	$ 220,027	3.18%	$ 6,997
53	392	TRANSPORTATION EQP	$ 75,199	4.09%	$ 3,076
54	393	STORES EQUIPMENT	$ 89,282	2.46%	$ 2,196
55	394	TOOLS, SHP, & GRG EQP	$ -	0.00%	$ -
56	395	LAB EQUIPMENT	$ -	0.00%	$ -
57	396	PWR OPERATED EQP	$ -	0.00%	$ -
58	397	COMMUNICATION EQUIP	$ -	0.00%	$ -
59	398	MISC EQP	$ -	0.00%	$ -
60		TOTAL GENERAL PLANT	$ 384,508		$ 12,269
61		TOTAL PLANT IN SERVICE	$ 328,064,833		$ 7,065,613

Sources:
Cols. A&C from OUCC Set 7 DEP 16, Attachment AU
Col. B from Schedule 1.

IURC Cause No. 43526
Northern Indiana Public Service Company's
Objections and Responses to
Office of Utility Consumer Counselor Seventh Set of Data Requests

OUCC Request 7-DEP-30:
a) Were the NIPSCO related amounts of the regulatory liability for cost of removal reported in NiSource's December 31, 2007 Form 10-K included in the depreciation reserves used by Mr. Spanos to calculate depreciation rates in this case? b) If not, please explain why not.
Objections:
Response:
The depreciation reserves used by Mr. Spanos to calculate depreciation rates in this case did not include the related amounts of the regulatory liability for cost of removal reported in NiSource's December 31, 2007 Form 10-K. The related amounts of the regulatory liability for cost of removal were excluded because these amounts would understate the depreciation reserve values used to calculate NIPSCO's electric rate base. For GAAP reporting purposes, the regulatory liability is created by reducing NIPSCO's accumulated reserve for the related cost of removal. If the accumulated reserve is understated, NIPSCO's net book value would be overstated thereby also overstating NIPSCO's electric rate base.

IURC Cause No. 43526
Northern Indiana Public Service Company's
Objections and Responses to
Office of Utility Consumer Counselor Twenty Third Set of Data Responses

OUCC Request 23-015
Please clarify the response to OUCC Set 7 DEP-030. a. Do the reserve amounts used by Mr. Spanos in calculating his proposed depreciation rates include those reserves that are related to accumulated cost of removal, which are reclassified as a regulatory liability on NiSource's/NIPSCO's GAAP financial statements? b. Or has Mr. Spanos reduced his reserve amounts by the amount of the cost of removal regulatory liability?
Objections:
Response:
As stated in response to OUCC Set 7 DEP-030, Mr. Spanos has not included amounts associated with the regulatory liability on NiSource's/NIPSCO's GAAP financial statements in the reserves used to calculate depreciation rates for regulatory purposes.

Business & Money

Fixing Depreciation Accounting

Accumulated provisions for depreciation belong on the right side of the balance sheet.

By John S. Ferguson

Until the late 1940s, the accepted accounting convention was to locate the accumulated provision for depreciation on the right (liability and capital) side of the balance sheet. The convention since has been to locate it on the left (asset) side as a contra-asset. This change was controversial, and has led to some strange accounting for the expenditures incurred to remove or abandon in place property, plant, and equipment (PP&E) at the end of its useful life (referred to here as removal costs or expenditures).

Recent events suggest now is an opportune time to revisit where the accumulated provision belongs. For example, the Financial Accounting Standards Board (FASB) and the International Accounting Standards Board are working to harmonize their respective standards. The Securities and Exchange Commission (SEC) announced its intention to allow financial reporting based on international accounting standards without reconciliation to U.S. generally accepted accounting principles (GAAP). And the SEC's advisory committee on improvements to financial reporting recommended that accounting rules avoid special treatment for specific industries. Finally, financial accounting has moved away from emphasizing the concept of matching to emphasizing fair value.

In this context, accounting practices might be poised for a change, putting accumulated provisions for depreciation back on the right side of the balance sheet.

Allocation, Not Valuation

The balance sheet location controversy didn't cease with moving the accumulated provision to the left side. For instance, a January 1959 *Accounting Review* article suggested that the location change be revisited.[1] In the article, a random sample of the then-recent annual reports of 90 industrials and railroads and 10 utilities showed one industrial, one railroad and three utilities continuing to report the accumulated provision on the right side, rather than as a contra-asset on the left side. Right-side treatment by utilities is not surprising, because utilities objected to the change 50 years ago.

Depreciation accounting is a cost-allocation concept—not a valuation concept—and an objection to left-side treatment was that it can lead some to incorrectly interpret the resulting net asset amount as being the current value of the assets. An objection to right-side treatment was that the accumulated provision is not a liability, so does not belong on the right side. The accumulated provision obviously isn't a liability, but it is a source of funds, and sources of capital are recorded on the right side. The removal or abandonment obligation clearly is a liability. However, the liability is the estimated expenditure measured at the price level expected at the time of expenditure, not the amount of the estimated expenditure already recorded as an expense and charged by regulated enterprises to their ratepayers.

For enterprises subject to price regulation, the accumulated provision clearly is a source of funds because rate-base regulation treats the accumulated provision as being ratepayer-supplied capital, for which a credit is provided at the allowed cost of capital. Recognizing »

depreciation as a source of funds also is evident from the U.S. government allowing income-tax depreciation to be accelerated in order to provide funds (tax savings) for business expansion. This view was reinforced when the initial attempts by price regulators to pass the tax savings on to ratepayers prompted the IRS to deny accelerated tax depreciation to entities not allowed to retain the resulting tax savings.

Being recorded as a contra-asset has led to concern that net asset amounts could become negative, which has led to some strange accounting for expenditures for removing or abandoning PP&E. For long-lived assets, salvage usually is inconsequential, and removal expenditures frequently exceed the historical cost of the related assets. Therefore, accurately recognizing these expenditures for accounting purposes is at least as important, if not more important, than is recognizing the consumption of the related PP&E when providing a product or service. However, accounting practices don't recognize this importance.

Regulatory agencies were well ahead of the accounting profession in recognizing that the concept of retirement accounting made no sense, and so adopted depreciation accounting. Under retirement accounting, investment is recorded as an expense upon retirement, salvage is recorded as income when received, and removal cost is recorded as an expense when incurred. Regulators also were ahead in recognizing there are three components to depreciation—investment, salvage, and removal expenditures—and that accurately charging these costs to ratepayers necessitates recording them ratably over the useful life of the related PP&E.

This recognition means a known investment cost is accrued (recorded as a periodic expense) after being incurred, an estimated future salvage amount is accrued (recorded as a periodic credit) before being received, and an estimated future removal expenditure is accrued (recorded as a periodic expense) before being spent. This treatment assures that ratepayers are charged no more and no less than the costs being incurred to serve them, at the time the service is rendered and the costs are incurred—which is known as the regulatory principle of intergenerational ratepayer equity.

Regulatory depreciation accounting rules are more detailed than are financial accounting rules, and are specified by the Uniform Systems of Accounts (USofAs) prescribed by FERC and other entities. Almost all USofAs dictate that salvage and removal costs be treated as components of depreciation,[2] and this treatment predates World War I. The basic foundation for the regulatory accounting treatment of salvage and removal cost is evident from the FERC USofAs for electric utilities and natural gas companies, which define depreciation as "loss in service value," define service value as "the difference between original cost and net salvage value," and define net salvage value as "the salvage value of property retired less the cost of removal."

Depreciation Under GAAP

Depreciation accounting is a system of accounting that aims to distribute cost or other basic value of tangible capital assets, less salvage value (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner.

It's a process of allocation, not of valuation. Depreciation for the year is the portion of the total charge under such a system that is allocated to the year. Although the allocation properly may take into account occurrences during the year, it's not intended to be a measurement of the effect of all such occurrences.—*JF*

54 percent of the total accretion is recorded after the unit ceases to operate and generate revenues. This is really strange accounting.

Salvage vs. Net Salvage

It took a while, but the U.S. accounting profession eventually caught up with the regulators, evident from the definition of depreciation given in a sidebar that was issued during the 1950s. Three aspects of this definition are significant to the treatment of removal costs—the requirement to be systematic and rational, consideration of salvage, and recognition that depreciation accounting is a process of allocation, not of valuation.

The rational aspect of "systematic and rational" means that depreciation is to be recorded in a manner that matches the pattern of usage or revenue-generating capability of the related assets, consistent with the regulatory principle of intergenerational ratepayer equity. Thus, if the asset usage or revenue pattern is decreasing, the depreciation method should be accelerated relative to the life span of the asset. If the pattern is constant, depreciation should be constant relative to the life span, and if the pattern is increasing, depreciation should be deferred relative to the life span.

The PP&E of regulated entities exhibits decreasing or constant patterns over their lifetimes—not increasing patterns. Therefore, U.S. GAAP dictates that the depreciation rates of such entities (and probably of all entities) be constant (rarable) over life defined by either

time or asset usage.

The U.S. GAAP definition reference to salvage is intended to mean "net salvage," thereby encompassing removal costs. If the definition had been meant to incorporate only salvage into depreciation, it would have stated "gross salvage" rather than merely "salvage." This terminology has proven to be unfortunate, because it has created confusion concerning how removal costs are to be dealt with for accounting purposes. As a result, the true intention of the GAAP definition has been lost, and strange accounting has occurred.

Several facts support the "net salvage" definition of "salvage" within GAAP. At the time of the definition, the term "salvage" generally was used to mean "net salvage" (*i.e.,* salvage proceeds less removal expenditures), and utilities typically incorporated removal costs into depreciation for regulatory accounting purposes. Additionally, the "net salvage" definition supports greater consistency in treating different end-of-life transactions (salvage and removal costs) ratably through depreciation. Treating removal costs differently from investment and salvage conflicts with the premise that accounting practices should be reliable and relevant.

The ratable treatment of removal costs through depreciation for regulatory accounting purposes has a long history, but periodically is challenged by proposals to defer recording and recovery. Such challenges also have a long history, but have taken on renewed vigor as a consequence of FASB Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations,* (SFAS 143), issued in 2001.

Challenges to ratable treatment of removal costs for regulatory purposes are unfortunate, because they lead to proposals for deferral mechanisms that, if accepted by regulators, increase the costs to be borne by ratepayers over the life of the related PP&E, thereby increasing energy costs and damaging the competitiveness of the state[3] (*see "Depreciation Shell Game," Fortnightly, April 2008*).

Removal cost deferrals result from regulatory decisions that emphasize near-term political considerations over long-term economic considerations. The financial community and large energy users can be expected to interpret such regulatory unfairness as signaling deterioration of the business climate. The financial community might react to such a signal by downgrading the securities of jurisdictional entities and of the state itself. Additionally, large energy users typically work from multiple locations, so they can shift production between locations in reaction to regulatory decisions—and sometimes they do. Large energy users participating in regulatory proceedings typically emphasize long-term considerations, through addressing cost-allocation (equity) issues, rather than issues concerning the magnitude of cost of service. It's not unusual for such users to react to a business-climate deterioration signal by shifting from emphasizing equity to emphasizing the near-term cost-of-service magnitude in their participation in regulatory proceedings.

> The removal obligation clearly is a liability, but rate-base regulation treats accumulated provisions for depreciation as ratepayer-supplied capital.

SFAS 143 is an example of the movement away from emphasizing matching to emphasizing fair value. It segregates retirement obligations (removal expenditures) imposed by law, stature, regulation or contract (legal obligations) from depreciation, and specifies that such obligations be recorded as liabilities—not as depreciation. The specified treatment is to record the initial discounted amount of the expected expenditure as part of the depreciable cost of the related asset and as an initial liability, and to record future accretion—due to the discounting unwinding over time—as accretion expense. This treatment is a single-payment (prepaid) annuity, but is recorded in a manner that gives it a structure similar to a multiple-payment annuity—the typical form of sinking-fund depreciation.

SFAS 92, *Regulated Enterprises—Accounting for Phase-in Plans,* defines annuity methods of depreciation as phase-in plans that are precluded from use for either regulatory or financial accounting purposes, unless the practice was regulatory policy prior to 1982. SFAS 143 side steps this limitation by classifying legal obligations as liabilities, so the specified treatment is not required to be "rational." Also, SFAS 92 is interpreted as applying only to investment, which is another consequence of the accumulated provision being on the left side of the balance sheet.

The deferral inherent in SFAS 143 treatment is evident in the obligation for decommissioning a nuclear generating unit, which is the obligation that prompted issuance of SFAS 143. A nuclear unit that receives a renewed operating license from the Nuclear Regulatory Commission is likely to have an operating life span of about 55 years. If decommissioning occurs 10 years after operations cease and the SFAS 143 discount rate is 8 percent, then 99.3 percent of the obligation would be recorded as accretion over 65 years, with the accretion amount recorded during the final year being 137 times the amount

recorded during the first year, and 54 percent of the total accretion being recorded after the unit ceases to operate and generate revenues—and, for a single-asset entity, after the enterprise ceases to be viable. This is really strange accounting.

Intergenerational Equity

The exposure draft of what eventually became SFAS 143 called for liability treatment of both legal and constructive obligations, which is the same as for international standards. However, SFAS 143 was limited to only legal obligations when FASB concluded that constructive obligations could not be defined tightly enough for consistent application, which suggests the international standard is not consistently being applied.

Limiting SFAS 143 to legal obligations did not preclude inconsistent application, and the FASB felt the need for clarification through issuing FASB Interpretation 47, *Accounting for Conditional Asset Retirement Obligations*, (FIN 47) in 2005. FIN 47 improved the consistency of reporting, but did not eliminate the problem—which is due, in part, to the difficulty in applying SFAS 143 by entities practicing the group concept of depreciation accounting. However, the remaining inconsistency pales when compared to the inconsistency resulting from the misinterpretation of the GAAP definition of depreciation accounting.

This misinterpretation means that regulated entities record removal or abandonment obligations ratably over the life of the related PP&E, except for a few that are subject to the jurisdiction of regulatory agencies that have imposed deferral mechanisms. At the same time, non-regulated entities record such obligations using one of two deferral mechanisms—SFAS 143 treatment for legal obligations, and cash treatment for other obligations. Entities practicing the item concept of depreciation accounting record and depreciate each item of PP&E separately, so related legal removal obligations easily are identified, recorded and tracked. Entities practicing the group concept easily can identify, record, and track such obligations for PP&E recorded and depreciated by location, such as for power plants, but it is next to impossible to track such obligations for PP&E not so recorded and depreciated, such as for electric and gas distribution systems.

> Using the group concept of depreciation accounting, it's nearly impossible to track legal obligations for electric and gas distribution systems.

SFAS 71, *Accounting for the Effects of Certain Types of Regulation*, allows qualified entities to utilize accounting practices that cannot be utilized by non-qualifying entities. The effect of qualification is that the income statement reflects regulatory accounting requirements, with any differences from financial accounting requirements being disclosed on the balance sheet as regulatory assets or liabilities. For example, obligations qualifying for liability treatment under SFAS 143 typically are reflected in depreciation for ratemaking purposes, so depreciation treatment would be reflected on the income statement and a regulatory liability disclosed. Disclosing a regulatory liability means that regulated entities must maintain accounting records for both depreciation treatment and liability treatment of legal obligations. SFAS 71 would be rescinded, if the SEC follows the recommendation of its advisory committee to avoid special treatment for specific industries. Rescinding would be a problem for regulators, because the financial statements of regulated entities could no longer match removal costs to the usage of the PP&E providing service to ratepayers, thereby violating the principle of intergenerational ratepayer equity.

It wouldn't be difficult to eliminate the strange removal cost accounting and the potential for violating the principle of intergenerational ratepayer equity. Doing so would allow financial statements to more accurately depict the financial position and results of operations of the reporting enterprises and ensure that ratepayers bear the costs being incurred to serve them. All that's necessary is to recognize that the accumulated provision for depreciation is a source of funds that belongs on the right side of the balance sheet, and to change the reference to "salvage" in the GAAP definition of depreciation accounting to "net salvage."

These two actions would allow FASB to rescind SFAS 143, and would promote consistency, comparability, reliability, and relevance by requiring all enterprises to use the same removal cost treatment for accounting purposes.

John Ferguson, CDP, formerly was a principal with Deloitte & Touche, and now chairs the current issues committee of the Society of Depreciation Professionals. This article reflects the views of the author and not Deloitte or the Society. Email him at johnferg@swbell.net.

ENDNOTES

1. Simon, Sidney, "The Right Side of Accumulated Depreciation" *Accounting Review*, Rutgers University, January 1959.
2. The only exception to incorporating removal or abandonment costs in depreciation that the author is aware of is the railroad USofA of the Surface Transportation Board, and that exception is limited to PP&E other than the track structure accounts.
3. Detrimental impacts easily are demonstrated, but are beyond the scope of this article.

Ready for IFRS?

International reporting standards are coming for U.S. public companies.

By Scott Hartman

Adoption of IFRS (International Financial Reporting Standards) in the United States undoubtedly would mark a significant change for many U.S. companies. It would require a shift to a more principles-based approach, place far greater reliance on management (and auditor) judgment, and spur major changes in company processes and systems.

But this change should not be feared. A move to IFRS also presents a tremendous opportunity. Moving to an entirely new accounting structure ultimately might enable companies to streamline reporting processes and reduce compliance costs.

IFRS has fewer bright lines and less interpretive and application guidance than does U.S. GAAP (Generally Accepted Accounting Principles). Companies will need to consider carefully the economic substance of their transactions and then apply the principles embodied in IFRS to that substance. Arguably, doing so might enable a closer alignment with underlying business objectives.

Many financial professionals in the power and utility industries today are aware of IFRS, which presently is used or under consideration in every major financial market around the world. There is a growing recognition, both in the United States and internationally, that a single set of high-quality global accounting standards offers real benefits. IFRS seems increasingly likely to provide that single set of standards.

Going Global

The Securities and Exchange Commission (SEC) is aware of the growing global acceptance of IFRS and has taken comments from listed companies, audit firms, investment groups, rating agencies, the legal community and government agencies in an effort to create a comprehensive plan for a smooth transition to using IFRS in the United States. These discussions take into consideration issues like whether to allow U.S. filers the option of either adopting IFRS or setting an effective date for implementation by all U.S. registrants.

The SEC hosted a roundtable meeting in August 2008 that focused on the performance of IFRS during the market turmoil that already was churning earlier this year. While panelists shared a general consensus that IFRS performed quite well, they acknowledged that challenges exist in the application of both IFRS and U.S. GAAP in areas such as fair-value accounting. In addition, the roundtable focused on accounting for off-balance sheet arrangements and commodity pricing, both topics of particular interest for the power and utility industries. Panelists also expressed the view that IFRS could benefit from additional application guidance to reduce certain inconsis- »

Five Steps to Implementing IFRS

■ **Step 1**: Develop goals: The company's management team and board of directors decide how best to present the company's financials on an ongoing basis. Then, preliminary mapping begins and high-level risk assessments are conducted, outlining the potential impact that IFRS can have on the company's balance sheet, financial reporting and accounting policies, tax liabilities, and contracts and joint venture agreements.

■ **Step 2**: Design and planning: The transition team validates the conversion recommendations made in Step 1 and evaluates the various options to determine the impact that different financial accounting and reporting policies will have across the enterprise.

■ **Step 3**: Solution development: New IFRS policies are modeled, and the transition team develops the process and system change requirements that the new guidelines require.

■ **Step 4**: Implementation: At its heart, implementation is a straightforward change-management effort that includes communication and training, followed by carrying out the agreed-upon approaches. At this step, the transition team can begin to test the new guidelines as implemented and remediate as needed.

■ **Step 5**: Post-implementation review: This occurs when all key parties—financial accounting and reporting, treasury, tax and others—meet to debrief and identify opportunities for improvement.

These five steps might take as long as two or three years from initial diagnostic discussions to post-implementation changes. This period allows for a thoughtful, well-planned transition that increases the long-term benefit of IFRS. Companies that wait—until either the SEC determines a definitive timeline or their competitors accelerate efforts toward transition—might find themselves playing catch-up.–*SH*

tencies as presently applied.

In late August, the SEC approved for public comment its long-awaited "Roadmap" to the eventual use of IFRS by U.S. companies. The proposed Roadmap anticipates mandatory reporting under IFRS beginning in 2014, 2015 or 2016, depending on the size of the issuer, and provides for early adoption in 2009 by a small number of very large companies that meet certain criteria. The SEC later might decide to allow other companies to adopt IFRS early, before the mandatory date of conversion. The roadmap also identifies several milestones that the SEC will consider in making its decision in 2011 about whether to proceed with mandatory adoption of IFRS.

While there are differences between U.S. GAAP and IFRS, the general principles, conceptual framework and accounting results between them are often the same, or similar, for most commonly-encountered transactions.

In general, IFRS standards are broader than their U.S. counterparts, with limited interpretive guidance. While U.S. standards contain underlying principles as well, the strong regulatory and legal environment in U.S. markets has resulted in a more prescriptive approach—with far more "bright lines," comprehensive implementation guidance and industry interpretations.

The International Accounting Standards Board (IASB) generally has avoided issuing interpretations of its own standards, preferring instead to leave implementation of the principles embodied in its standards to preparers and auditors, and its official interpretive body, the International Financial Reporting Interpretations Committee (IFRIC).

> The more principles-based approach of IFRS will present some unique challenges for regulated utilities.

IFRS Challenges

The more principles-based approach offered by IFRS will present some unique challenges for the regulated utility industry. With IFRS likely to arrive in the near—rather than distant—future, affected utilities should consider the implications of IFRS and start planning now.

■ **Accounting by regulated entities**: Under U.S. GAAP, FASB Statement No. 71, Accounting for the Effects of Certain Types of Regulation, regulated entities are allowed to account for certain incurred costs that will be able to be recovered through future rates as regulatory assets. Conversely, amounts previously collected but owed back to ratepayers are accounted for as regulatory liabilities. There is no comparable provision under IFRS, which means that, from the regularory-asset perspective, certain costs (including stranded costs from deregulation, fuel recoveries, storm damage, environmental remediation, and losses on refinancing to a name a few) will need to be written-off (despite the regulatory provision to recover such costs from ratepayers in the future). This would result in the recording of future revenues with no corresponding cost recognition.

■ **Property, plant and equipment**: Accounting for items such as property, »

plant and equipment may be more granular under IFRS than under U.S. GAAP. IFRS requires companies to account for fixed assets at the component level, which is defined as the unit of measurement to separately identify an asset, or part thereof, with a separately identifiable estimated useful life. Although most utilities account for assets using a retirement-unit level, reviewing current fixed-asset accounting records will help utilities determine which components should be depreciated over what estimated useful lives.

Lack of a parallel standard to Statement No. 71 in IFRS will mean that the treatment of gains and losses arising from disposal of assets belonging to regulated entities also will require review, as will the treatment of impairments and decommissioning obligations for current operating assets—particularly as the trend toward new nuclear generation and expansion into alternative energy sources continues. Policies that bear reviewing include those relating to allowable capitalized costs and accounting for subsequent replacement of components to make sure amounts are not overcapitalized on a company's balance sheet.

■ **Financial instruments:** This area poses probably the biggest conversion challenge. Commodity contracts and hedging activity play a significant part in the operations of utilities. Although the two relevant accounting standards, FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities (as amended for U.S. GAAP purposes), and IAS 39, Financial Instruments: Recognition and Measurement, generally are comparable, some fundamental differences merit utilities' consideration. Review of contractual language and details will be key: Reevaluating contracts will allow utilities to determine the proper accounting treatment in accordance with IFRS.

IFRS uses the "own-use" definition to exempt contracts that were entered into and continue to be held for the purpose of receipt or delivery of a non-financial item in accordance with the entity's expected purchase, sale or usage requirements. Certain hedging relationships—or the concept of normal purchases and normal sales—might be treated differently under U.S. GAAP than they are under IFRS and its related own-use determination. Under IFRS, it's also possible to hedge components (portions) of risk that give rise to changes in fair value. The overall valuation of financial instruments (specifically, considering the definition of fair value as set forth in the literature) and the accounting for day-one gains also may result in differing accounting results under the two standards.

> Certain hedging relationships might be treated differently under IFRS and its "own-use" determination.

■ **Accounting for joint ventures:** Currently, IFRS states that investments in associated companies are accounted for using the equity method, and investments in jointly controlled entities are accounted for under the equity method or proportionate consolidation. However, the treatment of joint ventures, including jointly-controlled assets, operations and entities, and the use of *pro rata* consolidation currently allowed under IFRS, are under review. This is another challenging area that likely will affect certain operating structures in place in the U.S. power and utilities industries. While varying structures allow companies to account for such joint ownership in the United States, some companies also have used the *pro rata* consolidation concept in U.S. GAAP-based financial statements to account for ownership interests in plants and related assets.

■ **Emissions:** Due to a worldwide focus on climate change, emissions generated by power and utility companies have received a lot of attention, and this also has raised accounting awareness. In addition, the recent District of Columbia Circuit Court of Appeals ruling in July 2008 striking down the U.S. Environmental Protection Agency's Clean Air Interstate Rule raised valuation and potential impairment issues related to nitrogen oxide and sulphur dioxide trading programs. This ruling has affected companies that began installing certain emissions-reduction control equipment at their plants. While both the Financial Accounting Standards Board (FASB) and IASB have accounting for emission allowances as current projects, neither U.S. GAAP nor IFRS currently sheds much light on any specific method of accounting for these allowances, resulting in at least two different methods of accounting. The two methods primarily focus on whether the emission allowances should be recorded as inventory or intangibles with the valuation question focused on whether to carry the allowances at historical cost or fair value. A related question arises as to whether an obligation should be recorded, and as of what date, related to a company's emissions.

IFRIC previously issued Interpretation 3 related to accounting in this area, but that interpretation was withdrawn, leaving unanswered questions about accounting for emissions. However, IASB recently added an Emission Trading Schemes project onto its agenda. The board tentatively decided that the scope of the project will address accounting for all tradable emission rights and obligations, and for activities to receive tradable rights in the »

future. Accounting commentary and literature increasingly address IFRS issues, so conversion likely will lend additional guidance in this area.

Agency Treatment

Investor-owned U.S. power and utility companies are regulated by the SEC as well as other entities, such as the Federal Energy Regulatory Commission (FERC) and local agencies of the states in which they operate. The accounting rules of FERC and other regulatory agencies heavily have influenced the accounting policies guiding U.S. utilities. To date, IFRS makes no allowance for other regulators, and this is not likely to be covered by the continuing SEC roundtable and other planning discussions.

At this point, FERC isn't expected to change its Uniform System of Accounts simply because of a proposed U.S. conversion to IFRS. Even if a change eventually would be forthcoming, it wouldn't happen until after U.S. issuers convert to IFRS.

For most industries, IFRS ultimately might enable companies to streamline reporting processes and reduce the cost of compliance. However, for U.S. power and utility companies, if the concepts of Statement No. 71 are not adopted or embraced by IFRS rule makers, accounting practices mandated by FERC and other regularory bodies might result in the requirement to maintain a separate set of financial records, similar to the process for current statutory reporting in certain international jurisdictions. The need to generate the required accounting information could have significant implications for a company's information-technology system. As a result, these companies would need to continue evaluating accounting for industry-specific issues and how it affects their IFRS planning.

> Momentum is building for U.S. adoption of IFRS, and conversion no longer appears to be a matter of "if," but more a matter of "when" and "how."

In any case, momentum is building for U.S. adoption of IFRS, and conversion no longer appears to be a matter of "if," but more a matter of "when" and "how." For companies that report in multiple jurisdictions, the adoption of a single global set of accounting standards can be a benefit in terms of process standardization and related efficiency gains. Multiple approaches to financial reporting continue to be inefficient and troublesome, and many affected companies strongly support the SEC's continued efforts in the U.S. transition to IFRS.

The question that power and utility executives and directors need to tackle—sooner, rather than later—is how they can maximize the opportunities presented by IFRS and effectively and efficiently deal with any challenges as a result of the conversion. The straightforward answer is to start planning now, dedicate the appropriate management focus and create a project team across all aspects of the company—including the financial accounting and reporting, tax and IT departments—to assess the effort and work toward transition activities. Also, it's never too early to begin educating analysts and investors on how a conversion to IFRS might impact the company's financial results.

Now is the time to begin planning for conversion from GAAP to IFRS. The resources needed and the impact on the organization will be far-reaching. But with proper strategic planning, benefits can be substantial.

Scott Hartman is executive director with Ernst & Young Assurance and Advisory Business Services.

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IURC Cause No. 43526
Northern Indiana Public Service Company's
Objections and Responses to
Office of Utility Consumer Counselor Twentieth Set of Data Responses

OUCC Request 20-001

The following questions relate to the impending accounting move from U.S. GAAP to International Financial Reporting Standards ("IFRS").

a. Please provide a narrative explanation of the anticipated impact of moving from U.S. GAAP to IFRS.
b. When does NIPSCO expect to adopt IFRS?
c. Please provide all analyses, quantifications, reports, studies, etc. that NIPSCO has conducted regarding the adoption of IFRS.
d. Please provide a specific discussion of how the change to IFRS will impact NIPSCO's accounting calculations and entries relating to SFAS No. 143, FIN No. 47 and the existing regulatory liability for cost of removal, SFAS No. 71 and the difference between financial and regulatory accounting.
e. Please provide a specific discussion of how the change to IFRS will impact NIPSCO's accounting calculations and entries relating to depreciation, accumulated depreciation, gross salvage and cost of removal. Please include a discussion of any difference between financial and regulatory reporting relating to these items.
f. Please provide a specific discussion of how the change to IFRS will impact NIPSCO's accounting calculations and entries relating to current income taxes, deferred income tax expense and accumulated deferred taxes. Please include a discussion of any difference between financial and regulatory reporting relating to these items.
g. Please identify all items and accounts currently classified as contra-accounts, deferred debits and credits, liabilities and assets which will or may flow to equity upon the replacement of GAAP with IFRS.

Objections:

NIPSCO objects to OUCC Set 20-001 on the grounds and to the extent that such Request solicits an analysis, calculation or compilation which has not already been performed and which NIPSCO objects to performing as well as on the grounds and to the extent that such Request seeks documents or information which are not relevant to the subject matter of this proceeding and to the extent they are not reasonable calculated to lead to the discovery of admissible evidence.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

a.-c. The adoption of IFRS will be managed by the NiSource Accounting Research Department.

IURC Cause No. 43526
Northern Indiana Public Service Company's
Objections and Responses to
Office of Utility Consumer Counselor Twentieth Set of Data Responses

NiSource continues to follow developments related to the proposed move from U.S. GAAP to International Financial Reporting Standards ("IFRS"). On November 14, 2008, the SEC issued its proposed IFRS "roadmap". The roadmap outlines several milestones that need to be addressed before making adoption to IFRS mandatory. The SEC will then determine in 2011 whether to require mandatory adoption of IFRS for all U.S. issuers. According to the roadmap, large accelerated filers, including NiSource, would be required to file IFRS financial statements in 2014.

d.-g. See objection. NiSource is not able to address the specific questions above at this time. The proposed accounting changes are very complex and comprehensive and impact almost all areas of accounting. For example, there is no equivalent of SFAS 71, "Accounting for the Effects of Certain Types of Regulation" in IFRS. During 2009, NiSource will develop a detailed project plan to begin analyzing the requirements of IFRS. Detailed recommendations from that study will likely result in system and process changes throughout the organization.