

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC )  
SERVICE COMPANY LLC PURSUANT TO IND. )  
CODE §§ 8-1-2-42.7, 8-1-2-61 AND IND. CODE § )  
8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS )  
RATES AND CHARGES FOR ELECTRIC )  
UTILITY SERVICE THROUGH A PHASE IN OF )  
RATES; (2) APPROVAL OF NEW SCHEDULES )  
OF RATES AND CHARGES, GENERAL RULES ) CAUSE NO. 45159  
AND REGULATIONS, AND RIDERS; (3) )  
APPROVAL OF REVISED COMMON AND )  
ELECTRIC DEPRECIATION RATES )  
APPLICABLE TO ITS ELECTRIC PLANT IN )  
SERVICE; (4) APPROVAL OF NECESSARY )  
AND APPROPRIATE ACCOUNTING RELIEF; )  
AND (5) APPROVAL OF A NEW SERVICE )  
STRUCTURE FOR INDUSTRIAL RATES. )

Verified Direct Testimony and Exhibits of

James A. Lahtinen

On behalf of

NLMK Indiana

February 13, 2019

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STRUCTURE FOR INDUSTRIAL RATES. )

**Direct Testimony of James A. Lahtinen**

1 Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

2 A My name is James A. Lahtinen, and my business address is 34 Founders Green, Pittsford,  
3 NY 14534.

4 Q WHAT IS YOUR OCCUPATION?

5 A I am an independent economic and financial consultant advising clients on matters  
6 involving regulatory policy, rates, and costs.

7 Q WHAT EXPERIENCE DO YOU HAVE REGARDING THE ISSUES IN THIS  
8 PROCEEDING?

9 A Prior to February 2017, I was employed for 12 years as Vice President of Rates and  
10 Regulatory Economics for Rochester Gas & Electric Company. RG&E is a subsidiary of  
11 Avangrid Networks, Inc., which is comprised of eight electric and natural gas companies

1 serving over three million customers in New York and New England. In that position, I  
2 managed a team of accountants, financial analysts, and operation researchers supporting  
3 company decision making and litigation support for state and federal regulatory rate  
4 filings.

5 In addition, I also served as Vice President of Regulation for New York Transco during  
6 the period November 2014 to February 2017 and was responsible for regulatory filings  
7 before the Federal Energy Regulatory Commission. New York Transco is a member-  
8 owned company formed by New York's investor-owned utilities in late 2014 to construct  
9 and maintain electric transmission facilities to address public policy needs defined by the  
10 state's Public Service Commission. Its members include Con Edison Transmission, LLC,  
11 a subsidiary of Con Edison, Inc.; Grid NY, LLC, a subsidiary of National Grid PCL;  
12 Avangrid New York Transco, LLC, a subsidiary of AVANGRID, Inc.; and Central  
13 Hudson Electric Transmission, a subsidiary of CH Energy Group, Inc.

A summary of all my relevant experience and education is provided in Exhibit JAL-1.

14 **Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

15 A I am appearing on behalf of NMLK Indiana ("NLMK"). NLMK operates a steel mini-  
16 mill located in Portage, Indiana that specializes in the production of hot rolled coil. The  
17 company operates an electric arc furnace melt shop that produces continuous cast steel  
18 slabs and a hot strip rolling mill for further processing of slabs into flat rolled steel  
19 products. NLMK takes power from NIPSCO's high voltage facilities and consumes  
20 millions of kWh each month.

21 **Q WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

22 A The purpose of my testimony is to comment on NIPSCO's rate restructuring proposal to  
23 consolidate three existing large industrial classes (732, 733, and 734) into two new rate

1 classes (830 and 831) and to require its largest customers taking service under proposed  
2 Rate 831 to purchase their non-firm energy requirements from the wholesale markets  
3 administered by MISO or from third party suppliers. NIPSCO maintains that the  
4 proposed rate restructuring is motivated by pending and potential bypass efforts by its  
5 very large industrial customers. NIPSCO claims that the new 831 rate structure will offer  
6 these large customers enhanced opportunities to independently manage their energy costs  
7 while they accept greater exposure to market price and volatility risks. I explain below  
8 that the competitive threats facing NIPSCO's largest energy intensive customers are  
9 undeniable, why it is reasonable for NIPSCO to address the prospect of bypass by these  
10 customers at this time, and why NIPSCO's proposed rate restructuring is reasonable and  
11 necessary. In the event that the Commission does not approve NIPSCO's proposed  
12 restructuring of the large industrial rates, I recommend an alternative approach for  
13 allocating any revenue increase or decrease among NIPSCO's existing rate classes.

14 **Q WILL YOU OFFER ANY COMMENTS ON OTHER ASPECTS OF NIPSCO'S**  
15 **PROPOSED RATE FILING?**

16 **A** Yes. I will discuss NIPSCO's proposal to allocate generation production plant using a 4  
17 CP allocator, its proposal to set rates for the new large industrial non-firm rate (Rate 831)  
18 at the proposed system average rate of return (*i.e.*, at "parity"), and the reasonableness of  
19 NIPSCO's proposed mitigation of the rates of return of other customer classes. I also  
20 will address required changes to the Rate 831 rate design and NIPSCO's proposal to  
21 address any differences between anticipated and actual Rate 831 Tier 1 (firm service)  
22 contract enrollment amounts through a second stage rate filing. Finally, with respect to  
23 NIPSCO's proposed revenue requirement, I recommend that the Commission reject  
24 NIPSCO's proposal to accelerate book depreciation on generation plants that it

1 anticipates retiring within the next 10 years and instead recommend that NIPSCO retain  
2 the current depreciation accrual rates. Maintaining current depreciation accrual rates will  
3 help to mitigate overall customer rate impacts arising from this Cause. The amortization  
4 of the retiring plants can always be reexamined in subsequent rate proceedings.

5 **Q PLEASE COMMENT ON NIPSCO'S EXPRESSED RATIONALE FOR THIS**  
6 **RATE FILING.**

7 **A** NIPSCO witnesses Hooper and Kelly point to the following factors as the key drivers to  
8 its rate filing:

- 9 1. The need to restructure large industrial rates to address a "changing economic  
10 landscape."
- 11 2. NIPSCO's desire to accelerate the amortization of its coal-fired generating units  
12 (increase depreciation accrual rates) toward the early retirement dates announced in  
13 its most recent IRP.
- 14 3. NIPSCO's need to fully reflect in its base rates the benefits to consumers of the Tax  
15 Cuts and Jobs Act of 2017.

16 NIPSCO seeks an overall increase in its electric revenues of \$21.4 million, or 1.4%  
17 based on total requested retail revenues of \$1.545 billion. Because it deems this requested  
18 increase to be small, NIPSCO asserts that its filing is not motivated by the company's  
19 revenue request, but, as Mr. Hooper puts it, is really a "policy case dealing with the  
20 changing energy marketplace" (Hooper at p. 12). While these three factors are the  
21 primary driving factors, the case clearly is more complicated than that. Although  
22 NIPSCO seeks a \$21.4 million increase overall in retail revenues, the proposed base rate  
23 revenue increase exceeds \$111 million. That proposed net change in base revenues  
24 reflects not only the factors noted above, but shifting recovery of various items from

1 trackers to base rates, the movement in the other direction of RTO costs from base rates  
2 to the tracker mechanism, separately stating the UTR (which is currently recovered in  
3 base rates) on consumer bills, and other features requested by NIPSCO.

4 **Q PLEASE COMMENT ON NIPSCO'S EXPRESSED CONCERN REGARDING**  
5 **LARGE INDUSTRIAL BYPASS OR LOAD LOSS.**

6 A In my view, NIPSCO is entirely correct that the electric energy marketplace is changing,  
7 and changing rapidly. It is crucial to recognize that the basic observable changes (coal  
8 plant retirements, increased reliance on natural gas fired generation, and NIPSCO's  
9 interest in large scale renewable investments) are being driven by fundamental economic  
10 and technological developments, including especially the availability of low cost  
11 domestic natural gas supply. The Energy Information Administration's ("EIA's) most  
12 recent Annual Energy Outlook released at the end of January confirms that abundant  
13 natural gas supplies are expected to produce comparatively low gas prices for the  
14 foreseeable future. (See <https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf>). This affects  
15 both the ongoing economics of NIPSCO's coal-fired generation and the attractiveness of  
16 self-supply alternatives to NIPSCO's very large industrial loads.

17 Given NIPSCO's dependence on industrial customers for such a large component of its  
18 retail sales, and the concentration of those sales among a small number of large, energy  
19 intensive, competitively at-risk industrial customers, NIPSCO is compelled to respond  
20 constructively to potential loss of these loads through bypass or production relocation.

21 As the competitive rate advantage NIPSCO's industrial customers once enjoyed has  
22 eroded and global competitive pressures have mounted, NIPSCO's largest customers are  
23 being pushed to consider power supply service alternatives. This was jarringly illustrated  
24 by BP's petition last year to self-service most of its electric needs with generation from

1 Whiting Clean Energy (“WCE”) in Cause No. 45071. As Mr. Kelly explained further in  
2 response to Citizen Action Coalition’s Data Request 2-025, in this Cause, given the  
3 existing economic conditions and the large industrial customers’ desire for more market  
4 based choices, this is the appropriate time to address the threat. I agree with that  
5 assessment.

6 **Q DO YOU CONSIDER NIPSCO’S PROPOSED RATE RESTRUCTURING**  
7 **CHANGES FOR THE LARGE INDUSTRIAL RATE CLASS 831 TO BE**  
8 **REASONABLE?**

9 A Yes. Based on my previous experience, it is better to proactively deal with the threat of  
10 significant load loss rather than wait and deal with the consequences afterwards. I have  
11 examined the particular rate structure for Rate Class 831 and find, with the slight revision  
12 noted below, that it is a reasonable approach to enable large industrial customers the  
13 opportunity to actively manage the energy cost risks for their load. Under current rates,  
14 large, non-firm loads participating in Rider 775 are subject to economic interruptions as  
15 well as reliability curtailments in exchange for the demand credits offered under the  
16 provisions of the Rider. A customer electing to continue to operate during an economic  
17 interruption pays the spot wholesale energy price (the locational marginal price, or  
18 “LMP”). Generally, as I understand the proposed Rate 831, NIPSCO will expand that  
19 concept to treat all non-firm energy sales as a buy-through but without the assurance of  
20 the prevailing interruptible credits, which would be eliminated. Large industrial  
21 customers will be required to contractually commit to a base level of demand and energy  
22 (Tier 1) for a five-year term, accept reliability curtailment provisions for non-firm power  
23 purchases (under Tier 2 or Tier 3) based on MISO’s requirements for Load Modifying  
24 resources (“LMRs”), and be subject to full wholesale energy market risks for all non-firm

1 energy purchased. For this approach to make sense to large customers, the firm (Tier 1)  
2 rates must in the first instance be reasonable, and affected customers must have tools  
3 available to manage the market risks that will apply to all Tier 2 and Tier 3 energy  
4 purchases.

5 I note with respect to the first rate element of proposed Rate 831 that existing customers  
6 served on Rate 732 will face a significantly increased demand charge under NIPSCO's  
7 proposed Tier 1 rates. This approach materially impacts the risk-reward opportunities for  
8 existing Rate 732 customers that do not operate at exceptionally high load factors. For  
9 this reason, it is imperative that, as NIPSCO has proposed, the Rate 831 rates be designed  
10 to provide a rate of return that is not higher than the proposed system average rate of  
11 return (*i.e.*, be set at parity to the system return). With respect to the second element,  
12 NIPSCO's intent in proposing the Tier 2 and 3 options is to establish customer-  
13 determined risk management tools. These risk management tools are essential to this rate  
14 structure because the energy price volatility exposure that Rate 831 customers otherwise  
15 would encounter would be unacceptable. On balance, the proposed rate structure will  
16 allow large customers an enhanced ability to match energy market risks and opportunities  
17 with their unique load profiles and energy requirements. This approach is preferable to  
18 either a "no action" alternative that does not address bypass risks or further expansion of  
19 the current interruptible tariff provisions because the proposed approach creates a  
20 sustainable platform that allows competitively at-risk industrial customers to better  
21 determine an appropriate balance between expected power cost levels and volatility and  
22 curtailment risk.



1   **Q     HOW SHOULD NIPSCO’S RATE BE STRUCTURED IF THE COMMISSION**  
2   **DOES NOT APPROVE NIPSCO’S INDUSTRIAL RATE RESTRUCTURING?**

3   A     If the Commission rejects NIPSCO’s proposed industrial rate restructuring, NIPSCO  
4     should retain the current rate 732, 733 and 734 service offerings, apply any authorized  
5     base rate revenue increase, or decrease, on an equal percentage basis to all classes, and  
6     continue or expand its Rider 775 options. Apart from the reasons for the proposed rate  
7     restructuring, there is no reason to consolidate the existing large industrial rates,  
8     continuing the Rider 775 options would be essential, and an equal percentage increase or  
9     decrease, as NIPSCO has proposed for all service classes other than Rate 831, is a  
10    palatable mitigation approach under the circumstances presented. To be clear, however,  
11    NLMK agrees with NIPSCO that the proposed rate structure offers a more sustainable  
12    platform for preventing uneconomic bypass.

13   **Q     DO YOU AGREE WITH NIPSCO’S CLAIMS THAT APPROVAL OF THE**  
14    **PROPOSED RATE STRUCTURE SHOULD BE BENEFICIAL OVER THE**  
15    **LONG TERM TO OTHER RATE CLASSES?**

16   A     Yes. While in the short-term other classes will bear increased fixed cost recovery,  
17    NIPSCO proposes to mitigate the effects on smaller customers in its rate filing. Also, as  
18    noted below, retaining current depreciation accrual rates for its generating plants and  
19    other revenue requirement adjustments should further mitigate those effects. Rate  
20    impacts also could be moderated by phasing in the requested increase over a multi-year  
21    period if the Commission feels such treatment is necessary. While I am not offering a  
22    specific proposal in this case, such rate making treatment is a reasonable way to smooth  
23    customer class impacts overall while at the same time addressing the threat of bypass by  
24    large industrial customers. Over the long run, all NIPSCO customers benefit if NIPSCO

1 can retain its large industrial base. Given NIPSCO's vulnerability to significant bypass by  
2 its largest industrial customers, other customers are exposed to risk of even higher rates  
3 over the long term if the current rate structure is maintained without confronting the  
4 bypass risks.

5 **Q ARE YOU AWARE OF SITUATIONS AT OTHER UTILITIES WHERE**  
6 **SIGNIFICANT LOAD REDUCTIONS OF INDUSTRIAL CUSTOMERS CAUSED**  
7 **SEVERE IMPACTS?**

8 A Yes. In 1981, steel production in the Pittsburgh area peaked at 465,000 tons. One year  
9 later, steel production dropped to 250,000 tons – a 53% decline. It is interesting to note  
10 that in July of 1981, Duquesne Light Company established an historic system peak  
11 demand of 2,522 MW. In 1982, Duquesne's recorded system summer peak had fallen to  
12 2,031 MW – a 491 MW (19%) drop in a single year. During the prior 20 years,  
13 Duquesne Light had experienced average annual growth in peak demand of about 4%.  
14 After that sudden decline, Duquesne's system peak load did not recover to the 1981 level  
15 until 1994. As a consequence of this loss of load, the company found itself with  
16 substantial excess generation capacity that ultimately forced it to mothball the Phillips  
17 power station. I spent my initial years at Duquesne working with others in attempting to  
18 arrange for firm sales of this excess generating capacity into eastern PJM. I do not mean  
19 to suggest that the industrial load loss at Duquesne Light could have been avoided  
20 through rate structure changes or that a similar loss of load will result if NIPSCO's rate  
21 redesign is rejected. I bring this up to illustrate that a significant manufacturing load  
22 reduction can have significant systemwide impacts that can be long lasting.

1   **Q     WOULD YOU PLEASE COMMENT ON THE 4 CP ALLOCATON NIPSCO HAS**  
2   **PROPOSED IN THIS PROCEEDING?**

3   A     Yes. NIPSCO's proposal to allocate production costs based on a 4 CP allocator is  
4     consistent with cost causation given the strong summer peaking nature of NIPSCO's  
5     system. I am aware that NIPSCO has proposed this method in recent prior base rate  
6     cases and support its continued application in this Cause. I also am aware of the  
7     objections raised by other parties to the use of the 4 CP allocation method for demand-  
8     related generation costs in previous proceedings. It is not my intention here to argue the  
9     conceptual merits of all conventional approaches for allocating generation costs (*e.g.*, 4  
10    CP, 12 CP, average and excess, fuel offsets, marginal cost, etc.), but simply to affirm that  
11    the 4 CP method used by NIPSCO is clearly reasonable. NIPSCO witnesses Kelly and  
12    Hooper have made compelling arguments that the threat of bypass is real, and the BP-  
13    WCE petition tangibly supports the company's concern. This is not a debate concerning  
14    which method, in the abstract, is best, but which approach under current circumstances is  
15    most appropriate. The 4 CP method is a reasonable approach based on NIPSCO's system  
16    profile. Adopting a more energy-oriented method under any rationale would undermine  
17    NIPSCO's efforts to combat large customer bypass.

18   **Q     DO YOU AGREE WITH NIPSCO'S RATE DESIGN AND MITIGATION**  
19   **PROPOSALS?**

20   A     Yes. NIPSCO's proposed approach of designing Rate 831 at the proposed system average  
21    return and applying an across-the-board average increase to all other rate classes  
22    reasonably addresses both the industrial bypass and mitigation concerns. In my opinion,  
23    this is a reasonable and thoughtful compromise given the circumstances that must be  
24    addressed. Finally, it bears noting that equalizing class rates of return is a reasonable

1 goal in general, but blind adherence to this goal is not. For example, even if the proposed  
2 rates for rate class 831 produced a class rate of return below the system average the result  
3 would be reasonable if it helped alleviate the industrial bypass threat that exists.

4 **Q ARE YOU AWARE THAT NIPSCO HAS PROPOSED A SECOND STAGE RATE**  
5 **FILING IN PART TO ADDRESS ITS CONCERN THAT CUSTOMERS IN RATE**  
6 **CLASS 831 MAY CONTRACT FOR LESS TIER 1 DEMAND THAN THEY**  
7 **HAVE ASSUMED FOR THE TEST YEAR?**

8 A Yes. This concern is addressed in the testimony of Mr. Kelly in which he explained that  
9 the as-filed rates for Rate 831 were designed assuming that 184.556 MWs (measured at  
10 the customer meter) of NIPSCO's large industrial load would be enrolled in Rate 831's  
11 Tier 1 service. He explained that this level of demand was based on indicated expected  
12 firm demands after discussions with NIPSCO's five largest customers. Because those  
13 customers, as well as other customers that may be eligible for Rate 831, could elect  
14 different levels of firm service for Tier 1, NIPSCO proposes that customer choices  
15 regarding Tier 1, 2, and 3 contract levels be made within 30 days following the final  
16 order from the Commission in this rate proceeding. Once final contract demands are  
17 known NIPSCO would calculate any revenue excess or shortfall resulting from Tier 1  
18 subscriptions that vary from the estimated 184.556 MW, and proposes to incorporate that  
19 difference into the proposed second phase true up. He concludes that: "If, after the final  
20 order, the total amount of Tier 1 firm service chosen by the five largest industrial  
21 customers is different than 184.556 MW, final rates will be set in the Phase 2 rates to  
22 collect the appropriate revenue."

23 **Q PLEASE COMMENT ON THIS PROPOSAL.**

24 A NLMK opposes including a Rate 831 Tier 1 true-up in a second stage filing because it is

unnecessary and could produce material but unanticipated rate impacts. NLMK fully expects to subscribe to Tier 1 service based on the estimates it previously provided to NIPSCO and urges other very large industrial customers to commit to the firm service estimates that were provided to NIPSCO.

**Q IS THERE A MORE PRACTICAL SOLUTION TO NIPSCO'S PROPOSED SECOND STAGE TRUE-UP?**

A Yes. A simpler solution to NIPSCO's concern is to revise the contracting requirements contained in the proposed tariff. Rate 831 specifies a default level of firm Tier 1 service at 30,000 kW but allows a customer to opt to reduce that level to 10,000 kW (Petitioner's Exhibit 19, Attachment 19-A, sheet 80). The tariff should instead specify that the minimum level of Tier 1 service shall be 30,000 kW except in the case of non-firm (Rider 775) customers that historically have subscribed to a lesser amount of firm service. In the latter case, the customer may opt to take firm service at the greater of their historic level of firm service or 10,000 kW. This revision would largely ensure against a significant shortfall in projected overall Tier 1 enrollment of 185 MW assumed in NIPSCO's filing, and should render a second stage true-up unnecessary. If a true-up were to be permitted, it should only be adjusted upward if enrollment exceeds NIPSCO's assumption to preclude a material overcollection of NIPSCO's fixed costs through the Tier 1 rates. I have included a redline of the proposed tariff to incorporate this proposed modification as Exhibit JAL-3.

**Q PLEASE DISCUSS NIPSCO'S PROPOSAL TO ACCELERATE DEPRECIATION FOR THE PLANNED RETIREMENT OF ITS COAL UNITS**

A. NIPSCO witness Augustine explained the company's rationale for determining to retire its remaining Shahfer coal-fired generating units in 2023 and Michigan City unit 12 in

1        2028. Those units had been expected to remain in service through 2035 and 2040,  
2        respectively. For rate purposes rather than to readjust those rates to reflect the newly  
3        announced new planned retirement dates, NIPSCO proposes to recalculate its  
4        depreciation accrual rates for the units through the year 2030. While NIPSCO intends the  
5        arbitrary proposed 2030 date as a means of mitigating the rate impact of the early  
6        retirement of the remaining coal units, the proposed accelerated recovery of plant costs  
7        nonetheless imposes an unnecessary and unanticipated increase in consumers rates. I  
8        suggest that NIPSCO retain its current accrual rates for the coal-fired units in this case in  
9        order to mitigate overall customer rate impacts. The depreciation rates for the coal units  
10       can always be reassessed in subsequent NIPSCO rate cases if circumstances warrant.

11    **Q       DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

12    **A       Yes.**

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CAUSE NO. 45159

Verification

I, James A. Lahtinen, verify under the penalties of perjury that the foregoing statements  
are true and correct to the best of my belief and knowledge.



James A. Lahtinen

***Curriculum Vitae of James A. Lahtinen***

**Work History**

**2014-2017 New York Transco Vice President, Regulatory**

- Responsible for federal regulatory policies, filings, and compliance

**2002-2017 Rochester Gas and Electric Corporation (RG&E) Vice President, Rates & Regulatory Economics**

- Oversight of Rates & Regulatory Economics Department for both NYSEG and RG&E
- Developed regulatory strategies in support of corporate goals
- Expert witness in major rate proceedings
- Represented companies in collaborative proceedings involving NYS PSC Staff and other parties

**2001-2002 Duquesne Light Company Vice President, Rates**

- Oversight of Rates, Regulatory Affairs, and PUC customer complaint unit
- Responsible for state and federal rate-related and regulatory policy matters
- Worked on developing Duquesne's supply solicitation to meet its provider of last resort obligations

**1999-2001 AquaSource Inc. (affiliate of Duquesne Holdings Co.) Vice President, Rates & Regulatory Affairs**

- Overall responsibility for all rate case and rate-related matters across 11 state jurisdictions
- Responsible for major base rate filings
- Responsible for financial valuation of target acquisitions

**1996-1999 Duquesne Light Company General Manager, Rates & Regulatory Analysis**



- Managed electric rate department comprised of economists, accountants, and electrical engineers
- Oversight responsibility for Company's integrated resource plan, including electric restructuring plan development
- Responsible for retail and wholesale rates and tariffs, including transmission pricing and policies

**1991-1996 Duquesne Light Company Manager, Transmission Services**

- Developed and filed Duquesne's first FERC transmission tariff
- Responsible for developing business and regulatory strategies to secure long term firm transmission service from neighboring utilities

**1989-1991 Bower Rohr & Associates Consultant**

- Provided economic and financial consulting counsel to various clients
- Provided litigation support in regulatory and civil matters
- Provided expert testimony before regulatory commissions

**1984-1989 Central Vermont Public Service Corporation Director, Regulatory and Economic Analysis**

- Managed small team of economists and accountants
- Responsibilities included demand forecasting, cost of service studies, and rates
- Policy witness in several contested regulatory proceedings

**1979-1984 Other Work Experience**

- Staff economist New York State Consumer Protection Board (1979-1981)
- Staff economist New York State Department of Public Service (1981-1984)

**Education**

- B.A., Economics – State University of New York at Plattsburgh
- M.A., Economics – State University of New York at Albany

**James A. Lahtinen**  
**Testimony in Regulatory Proceedings**

1. Connecticut: Department of Public Utility Control
  - a. Department of Public Utilities Control, Eastern Connecticut Regional Water Company, Docket No. 98-12-20 (1999) for AquaSource Utility, Inc.
2. District of Columbia: Public Service Commission
  - a. District of Columbia Public Service Commission – OE/PEPCO Power Purchase Agreement, Docket (Unknown), for People’s Counsel
  - a) Federal Energy Regulatory Commission:
    - a. Open Access Transmission Tariff, Docket No. ER96-T8-ER9-1543 (1996) for Duquesne Light Company
    - b. Allegheny Open Access Transmission Tariff, Docket No. ER96-58-000 (1996) for Duquesne Light Company
    - c. Request for Firm Transmission from Pennsylvania-Jersey-Maryland Power Pool, Docket No. TX94-8-000 (1995) for Duquesne Light Company
    - d. Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act, Docket No. RM94-20-000 (1995) for Duquesne Light Company
4. Indiana: Indiana Utility Regulatory Commission
  - a. Indiana Utility Regulatory Commission, Cause No. 41968, for Utility Center, Inc.
5. Maine: Maine Public Utilities Commission
  - a. Maine Public Utilities Commission, Docket No. 2013-168 (2013) for Central Maine Power Company
6. New Hampshire: Public Service Commission
  - a. New Hampshire Public Utility Commission, Consolidated Docket Nos. DR86-41, 86-70, 86-71 and 86-72 (1987) for the Connecticut Valley Electric Company, Inc.
  - b. New Hampshire Public Utility Commission, Consolidated Docket No. DR85-401 (1986) for the Connecticut Valley Electric Company, Inc.
  - c. New Hampshire Public Utility Commission, Consolidated Docket No. DP85-351 (1985) for the Connecticut Valley Electric Company, Inc.
7. New Jersey: Board of Public Utilities

- a. New Jersey Board of Public Utilities, Ellesor, Inc., BPU Docket SR 087121407, SR 8806732, SR 88121309 and SR 88121310 (12/20/89) for the Union County Utilities Authority
8. New York: State Public Service Commission
- a. Proceeding to Inquire into the Benefits of Conservation Programs, Case No. 28223 (1983) for the New York State Department of Public Service
  - b. Niagara Mohawk Power Corporation Case No. 28525 (1983) for the New York State Department of Public Service
  - c. Long Island Lighting Company – Shoreham Ratemaking Principles Case No. 28252 (1983) for the New York State Department of Public Service
  - d. Fuel Adjustment Clause Case No. 27741 (1982) for the New York State Department of Public Service
  - e. New York State Electric and Gas Case No. 28167-9 (1982) for the New York State Department of Public Service
  - f. Nine Mile Point No. 2 Nuclear Station Case No. 28059 (1983) for the New York State Department of Public Service
  - g. New York Telephone Company Case No. 27995 (1981) for the New York State Department of Public Service
  - h. Niagara Mohawk Power Corporation Case No. 27741 (1982) for the New York State Department of Public Service
  - i. New York State Electric and Gas Case No. 27882-4 (1981) for the New York State Department of Public Service
  - j. Rochester Gas and Electric Corporation Case No. 27831-4 (1980) for the New York State Department of Public Service
  - k. New York Telephone Company Case No. 27710 (1981) for the New York State Department of Public Service
  - l. New York State Electric and Gas Case No. 27546 (1980) for the New York State Department of Public Service
  - m. Niagara Mohawk Power Corporation Case No. 27538-4 (1979) for the New York State Consumer Protection Board
  - n. Consolidated Edison Case No. 27544 (1979) for the New York State Consumer Protection Board

- o. Long Range Electric Plans – Phase II, Case No. 27319 (1979) for the New York State Consumer Protection Board
  - p. State of New York – State Energy Master Plan and Long Range Electric and Gas System Planning Proceedings (1979) for the New York State Consumer Protection Board
  - q. Central Hudson Case No. 27461-2 (1979) for the New York State Consumer Protection Board
  - r. Brooklyn Union Gas Case No. 27275 (1978) for the New York State Consumer Protection Board
  - s. Niagara Mohawk Power Corporation Case No. 27215-7 (1977) for the New York State Consumer Protection Board
  - t. Orange & Rockland Case No. 27094/S (1977) for the New York State Consumer Protection Board
9. Pennsylvania: Public Utility Commission
- a. Petition for Approval of Plan for Post-Transition Period POLP Service (2002) Docket No. R-00974109
  - b. Restructuring Plan for Duquesne Light Company (1998) Docket No. R-00974104
  - c. Retail Access Pilot Program for Duquesne Light Company (1997) Docket No. P-00971175
  - d. *Township of Springdale vs. Duquesne Light Company* (1996) Docket No. C-00967749
10. Vermont: Public Service Board
- a. Vermont Public Service Board, Docket No. 5270 (1988) for Central Vermont Public Service Corporation
  - b. Vermont Public Service Board, Docket No. 5189 (1987) for Central Vermont Public Service Corporation
  - c. Vermont Public Service Board, Docket No. 5132 (1986) for Central Vermont Public Service Corporation
  - d. Vermont Public Service Board, Docket No. 5030 (1985) for Central Vermont Public Service Corporation
  - e. Vermont Public Service Board, Docket No. 5045 (1986) for Central Vermont Public Service Corporation

- f. Vermont Public Service Board, Docket No. 4947 (1985) for Central Vermont Public Service Corporation
- g. Vermont Public Service Board, Docket No. 4906 (1985) for Central Vermont Public Service Corporation
- h. Petition for Several Applicants for Certificates of Public Good to Provide Cable Television Service in the State of Vermont, Docket No. 5333 (1990) for Island Endeavors, Inc. and Mountain Cable Company

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**TO WHOM AVAILABLE**

Available to Industrial Customers taking service at Transmission or Subtransmission voltage whose Premises are located adjacent to existing electric facilities having Transmission or Subtransmission capacity sufficient to meet the Customer's requirements. Customer shall contract for a definite amount of electrical demand which shall not be less than 10,000 kW. The Company shall not be obligated to supply electrical Energy in excess of the definite amount specified in the contract.

For multiple Premises held under common ownership or by affiliates (as defined in Indiana Code § 23-1-43-1) and having the same qualifying service voltage, Interval Data Recorder (IDR) meters with 5-minute interval telemetry capability at those Premises can be aggregated for billing purposes if at least one of those meters has a load of 10,000 kW or more for the last 12 months. Transmission charges will be applied to the gross energy consumption (not netted with potential outputs from other qualifying meters) of each individual IDR meter. Netting for Transmission Charges will be allowed for multiple meters at each Customer Premise. The specific IDR meters that will be applied for aggregation will be specified in the contract.

**CHARACTER OF SERVICE**

The Company will supply metered Transmission or Subtransmission service to the extent of the Transmission capacity available from its electric supply lines, at such frequency, phase, regulation and voltage as it has available at the location where service is requested.

The Customer, at its own expense, shall furnish, supply, install and maintain, beginning at the point of delivery, all necessary equipment for transmitting, protecting, switching, transforming, converting, regulating, and utilizing said electric Energy on the Premise of the Customer.

The Customer will also supply in accordance with plans and specifications furnished by the Company and at a mutually agreed upon location on the Customer's property, suitable buildings, structures, and foundations to house and support the metering and any protecting, switching, and relaying equipment that may be supplied by the Company.

Customers electing Tier 2 and Tier 3 service shall contract for and specify a Tier 2 and Tier 3 Contract Demand for each affected Premise or aggregated Premises under this Rate Schedule. Tier 2 and Tier 3 service shall by default be curtailable. Customers electing service under Tier 2 and Tier 3 of this Rate Schedule shall specify the firm portion of their Tier 2 and Tier 3 Contract Demand for each affected Premise or aggregated Premises that the Customer intends to exclude from MISO Curtailment. Customers shall also meet the applicable Load Modifying Resource (LMR) requirements pursuant to MISO's Tariff Module E-1 or any successor if firm capacity is

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**CHARACTER OF SERVICE (Continued)**

not purchased or otherwise procured as allowed under Tier 2 and Tier 3. If a Customer's elected service under this Rate Schedule results in curtailable demand under Tier 2 and Tier 3, the Customer shall provide information necessary to satisfy these requirements, including information demonstrating to Company's satisfaction that the Customer has the ability to reduce load to any firm capacity within Tier 1, Tier 2, and Tier 3.

Any Applicant requiring service differing from that to be supplied by the Company as herein provided shall provide proper converting, transforming, regulating or other equipment upon Applicant's Premise and at Applicant's expense. (See Company Rule 3 for the Company's standard voltages.)

**SERVICE TIERS**

Tier 1: Firm Service

The default Tier 1 Contract Demand election is a minimum of 30,000 kW, provided, however, that an existing customer that was participating in Rider 775 and had a contract firm demand of a lesser amount may with an option to elect above or below that a Tier 1 amount down to the greater of its historic firm demand or 10,000 kW. The firm Energy is calculated on an hourly basis. This service is subject to applicable Riders as identified in Appendix A.

Tier 2: Non-Firm Market Price Service

The Customer's Tier 2 Contract Demand is the Customer's Planning Reserve Margin Requirement using the Company's forecasted Coincident Peak demand for the Customer less the Customer's Tier 1 Contract Demand election and any Tier 3 Contract Demand election by the Customer. This service is subject to applicable non-production Riders as identified in Appendix A. Customer will take all Energy under this Tier 2 service at Day-Ahead LMP at the applicable Company Load Zone (NIPS.NIPS) plus Transmission Charges contained within this Rate Schedule. By September 30 of each year, the Company will share with the Customer its Planning Reserve Margin Requirement, forecasted Coincident Peak demand and the supporting documentation for the values. Customer shall have 30 calendar days to dispute these values. The Company will make all reasonable efforts to resolve any such disputes; however, as the Market Participant, the Company is responsible for all forecasted needs and its subsequent forecast methodology, which is subject to audit by MISO. Company will submit the Customer's Planning Reserve Margin Requirements and Coincident Peak demand on November 1 of each year to comply with MISO's Resource Adequacy Requirements.

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**SERVICE TIERS (Continued)**

Tier 2 Contract Demand is firm only to the extent that it is supported by Customer-procured capacity. NIPSCO, as the Market Participant, will register as an LMR at MISO that portion of a Customer's Tier 2 Contract Demand for which capacity is not procured through MISO's PRA or contracted through a third party. Such portion of a Customer's Tier 2 Contract Demand is non-firm, subject to MISO Curtailment. Customers must meet all applicable LMR requirements pursuant to MISO's Tariff Module E-1 or any successor for this portion of their Tier 2 Contract Demand.

**Tier 3: Non-Firm Third Party Generation Service**

Customer may elect a Tier 3 Contract Demand up to Customer's Planning Reserve Margin Requirement using the Company's forecasted Coincident Peak demand for the Customer less the Customer's Tier 1 firm Contract Demand election. To the extent a Customer declines to elect the Tier 3 Contract Demand to which it is entitled under this Rate Schedule, it must elect to take Tier 2 Contract Demand. If the Customer elects to take any Tier 3 Contract Demand, NIPSCO, as the Market Participant, will register that Customer as an Asset Owner at MISO. Tier 3 service is subject to applicable non-production Riders as identified in Appendix A. If, under the MISO Asset Owner framework, a Customer has not arranged for any third party Energy with NIPSCO as the contracting Market Participant, Customer will take all Energy under this Tier 3 service at market price (LMP at the applicable Company Load Zone (NIPS.NIPS) plus all applicable MISO market settlement charges plus the Transmission Charge contained within this Rate Schedule. Customer will be responsible for all market settlement charges incurred by either NIPSCO as the Market Participant or the Customer as Asset Owner for any third party Energy or Capacity arrangements including, but not limited to, transmission charges to deliver energy. MISO Market Portal access will be provided as required to carry out MISO Asset Owner functions. All settlements associated with energy offers and demand bids will be passed through to the Customer. By September 30 of each year, the Company will share with the Customer its Planning Reserve Margin Requirement, forecasted Coincident Peak demand and the supporting documentation for the values. Customer shall have 30 calendar days to dispute these values. The Company will make all reasonable efforts to resolve any such disputes; however, as the Market Participant, the Company is responsible for all forecasted needs and its subsequent forecast methodology, which is subject to audit by MISO. Company will submit the Customer's Planning Reserve Margin Requirements and Coincident Peak demand on November 1 of each year to comply with MISO's Resource Adequacy Requirements.



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**SERVICE TIERS (Continued)**

Tier 3 Contract Demand is firm only to the extent that it is supported by Customer-procured capacity. NIPSCO, as the Market Participant, will register as an LMR at MISO that portion of a Customer's Tier 3 Contract Demand for which capacity is not procured through MISO's PRA or contracted through a third party. Such portion of a Customer's Tier 3 Contract Demand is non-firm, subject to MISO Curtailment. Customers must meet all applicable LMR requirements pursuant to MISO Tariff Module E-1 or any successor for this portion of their Tier 3 Contract Demand.

**METER FLOW AND CURTAILMENT ORDER**

Definition of meter flow shall be defined as follows:

Meter Flow	Service
↓	Applicable service taken under Rider 876
	Tier 1: Firm Service
	Tier 2: Market Price Service
	Tier 3: Third Party Generation Service

The above meter flow is for Energy only. For MISO Curtailments, the meter flow shall be defined as follows:

Meter Flow	Service
↓	Tier 2 and Tier 3: Non-Firm
	Applicable service taken under Rider 876

**MISO CURTAILMENT AND FIRM CAPACITY OPTIONS**

The Company shall dispatch Customers for MISO Curtailments at its own discretion in accordance with the limitations specified under this Rate Schedule and the Company Rules.

The Company shall register the portion of all Customer Contract Demand above its Tier 1 level as an LMR with MISO and shall be subject to MISO Curtailments under this Rate Schedule. Customer shall meet the applicable LMR requirements pursuant to MISO's Tariff Module E-1 or any successor. A Customer may elect to reduce all or part of its LMR obligation by procuring capacity in the MISO PRA or capacity through third party arrangements, at the Company's applicable zone defined within MISO's PRA. If Customer elects to reduce all or a portion of its LMR obligation through MISO's PRA, NIPSCO will self-schedule (price-taker) such capacity on the Customers behalf. Customers that fail to meet the requirements of a LMR or do not otherwise procure capacity will be subject to any capacity replacement/deficiency charges, and any penalties incurred as a result of maintaining Customer's Resource Adequacy needs.

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**MISO CURTAILMENT AND FIRM CAPACITY OPTIONS (Continued)**

Tier 2 Customers will be provided at least four (4) hours advanced notice of MISO Curtailments or if Customer has elected for both Tier 2 and Tier 3 service only a single LMR will be registered with MISO and aligned to Customer's Tier 3 notification. Tier 3 Customers will be able to determine a curtailment notification time and other parameters associated with registration as a LMR pursuant to the MISO Tariff and BPM.

In the event of a material change in circumstances due to a force majeure, or otherwise, that effects the ability of a Customer to comply with part or all of its LMR obligations with MISO, the Customer shall immediately notify the Company. The Company will in turn notify MISO of a need to change the Customer's LMR registration. Modifications to LMR intra to the MISO Planning Year may trigger replacement capacity provisions within the MISO Tariff and may require the Customer to procure replacement capacity or pay MISO capacity deficiency charges / penalties.

**MISO ASSET OWNER REGISTRATION**

For a Customer electing Tier 3 service, registration will follow MISO's quarterly network model update cycle. During quarterly network model updates, the Company will request registration of a CP Node which is required for participation as an Asset Owner under this Rate Schedule. The CP Node will be mapped to MISO EP Nodes in the same manner as the NIPS.NIPS CP Node to the extent model modifications are allowed under MISO Rules. Refer to the market registration section of the MISO BPM for details on the data required to register.

**COMMUNICATIONS, METERING, TELEMETRY, HARDWARE, AND SOFTWARE REQUIREMENTS**

The Company shall specify a communications plan, which includes a revenue quality meter and all implementation and operational software required under this Rate Schedule. It is the Customer's responsibility to comply with that plan. The Customer will pay for the installed cost of additional metering, telemetry, hardware and software development, certificates, and licensing fees that may be required to facilitate service under this Rate Schedule. All such metering shall be compliant with any applicable current and future MISO and/or IURC requirements, including the potential of meter capture on a 5 minute basis. The Customer shall provide the Company with next day remote interrogation of the meter on an hourly level. The Customer may elect to install its own metering, with the Company reserving the right to inspect the equipment and own the equipment once it is installed. At the Customer's request, metering may be installed by the Company and invoiced at the installed cost to the Customer. Estimated costs of metering and equipment shall be provided prior to installation by the Company, but the Customer shall be responsible for the actual costs of the equipment and installation.

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**DEMAND BIDS**

For a Customer electing Tier 3 service, the Customer will have the ability to submit Day-Ahead Demand Bids for a portion or all of their Tier 3 daily demand through the MISO Market Portal. Day-Ahead Demand Bids not received by MISO in accordance with the MISO BPM will be settled at Real Time LMPs and assessed any applicable additional MISO charges. Refer to the Demand Bid section of the MISO BPM for details on the requirements of the Demand Bid.

**MISO COMMUNICATIONS**

For a Customer electing Tier 3 service, all clearing, pricing and settlement activity will be available on the MISO Market Portal. Revenue quality meter data will be interrogated by the Company on a daily basis and submitted by the Company to MISO on behalf of the Customer.

**MISO SETTLEMENTS**

For a Customer electing Tier 3 service, MISO Settlement Statements are posted daily by MISO to the MISO Market Portal. The Customer shall obtain the MISO Settlement Statements from the MISO Market Portal. The Customer shall be responsible for the review of the Customer's MISO Settlement Statements. All charges reflected on the Customer's MISO Settlement Statements will be the Customer's responsibility and are payable to the Company on a weekly basis. MISO Settlement Statement charges will be determined by the Customer's Day-Ahead Demand Bid (at Day-Ahead LMP) and the imbalance between the Customer's Day-Ahead Demand Bid and the Customer's actual metered Demand (at Real-Time LMP). Any imbalance between the Customer's Day-Ahead Demand Bid and the Customer's actual metered Demand will also be assessed any applicable MISO charges including a Revenue Sufficiency Guarantee charge. MISO Settlement Statements will also include the Customer's share of Market Uplift charges and an administrative fee that is charged by MISO to support the operation of the market. The Customer's MISO Settlement Statements will follow the settlement timeline that is outlined in the MISO BPM, which may also include special resettlements that are deemed necessary by MISO. Refer to the MISO BPM for details on the MISO Settlement Timeline and Settlement Charge calculations.

**DISPUTES**

For a Customer electing Tier 3 service, the Customer has the right to dispute any MISO charges. The Customer, through the MISO Market Portal, will provide all required data to MISO to support the dispute. The Customer shall notify the Company of any filed disputes and disposition by MISO within 24 hours of such notification. Notification of disputes shall include a copy of the dispute submitted by the Customer along with any correspondence between the Customer and MISO including, but not limited to, the final resolution of the dispute. Notification shall be remitted to the Manager, Market Settlements of the Company.

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**DISPUTES (Continued)**

Disputes that have been denied by MISO may be disputed through the MISO Alternative Dispute Resolution (ADR) process in accordance with MISO Rules. The Company as the Market Participant must file ADR disputes on the Customer's behalf as currently Asset Owners cannot file an ADR. The Customer must provide written notification in compliance with the timelines established by Attachment HH of the MISO Tariff to the Company requesting the Company to proceed with the mechanism available to resolve these disputes outside of the judicial or administrative agency proceedings. This would include informal dispute resolution, or formal mediation or arbitration. The Company will make a good faith effort to prosecute the dispute. The Company will provide the Customer an initial preliminary estimate for costs associated with the ADR. Customer must submit payment in accordance with the estimate established if the Customer wishes to pursue the ADR at MISO. The written notification shall be remitted to the Manager, Market Settlements of the Company.

The hierarchy as it stands allows an Asset Owner to file the dispute with MISO. If the dispute is denied and the Customer wants to pursue it further, the Customer needs to request NIPSCO to file an ADR on its behalf with MISO. If the Customer is unsatisfied with MISO's decision, it can pursue a complaint with FERC on its own.

It is the responsibility of the Customer to pay all assessed MISO Settlement Statement charges to the Company when due at the time of assessment. Any necessary adjustments to the settlement amounts will be made by MISO after dispute resolution. Refer to the MISO BPM for details on the requirements of the Dispute and ADR process.

**REGISTRATION**

Customers electing non-firm service and or registration as an LMR will provide all required data to the Company per MISO's Resource Adequacy BPM. The Company may request additional data as requested by MISO to support any and all Resource Adequacy compliance requests. MISO's capacity Planning Year is June 1 through May 31. All required information must be entered prior to due dates to ensure capacity positions are established. Once the PRA has cleared, modifications can be made per limitations and penalties as outlined in MISO's Tariff Module E-1.

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**REGISTRATION (Continued)**

The following table provides an overview of Tier requirements. All requirements and dates are pursuant to MISO's Tariff Module E-1 or any successor and may be modified by MISO. Customer shall provide required information to the Company ten (10) business days prior to MISO Planning Resource Timeline in accordance with MISO BPM-011, Appendix K:

<b>Requirement</b>	<b>Tier 2</b>	<b>Tier 3</b>
Coincident Peak Demand forecast, Non-Coincident Peak, and energy forecast		X
Existing Load Modifying Resource/Energy Efficiency Resource must be submitted for approval	X	X
New Load Modifying Resource/Energy Efficiency Resource registration to be considered for inclusion in FRAP must be submitted for approval		X
New Load Modifying Resource/Energy Efficiency Resource must be submitted for approval	X	X
Planning Resource Auction offer window is open		X
Planning Resource Auction offer window is closed		X
Planning Resource Auction results posted		X

**DETERMINATION OF AMOUNT OF ELECTRIC SERVICE SUPPLIED**

The electric service to be supplied under this Rate Schedule shall be measured as to Maximum Demand, Energy Consumption and kVAR by an IDR to be installed by the Company.

**RATE**

Rates charged for service rendered under this Rate Schedule are based upon the measurement of electric Energy at the voltage supplied to the Customer.

After aggregation of Customer's Premises, Customer Energy delivered onto the Company's Transmission or Subtransmission system at an integrated hourly level shall be paid to the Customer at the Real Time LMP at the Company's Load Zone.

The electric service and Energy supplied hereunder shall be billed under a three-part rate consisting of a Demand Charge, Energy Charge, and Transmission Charge, and applicable Riders as identified in Appendix A. The Demand Charge, Energy Charge, and Transmission Charge are as follows:

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**RATE (Continued)**

**Demand Charge**

**Tier 1**

\$24.37 per kW per month

**Energy Charge**

**Tier 1**

\$0.029618 per kWh for all kWhs used per the month.

**Tier 2**

All kWhs used above the specified Tier 1 Firm Contract Demand shall be subject to an Energy Charge equal to the Day Ahead LMP for the Company's Load Zone, if Customer does not have a Tier 3 Contract Demand. If Customer has a Tier 3 Contract Demand, all kWhs used above the specified Tier 1 Firm Contract Demand not in excess of Tier 2 Contract Demand shall be subject to an Energy Charge equal to the Day Ahead LMP for the Company's Load Zone.

**Energy Charge (Continued)**

**Tier 3**

All kWhs used above the specified Tier 1 and Tier 2 Contract Demand shall be subject to MISO Settlement Charges related to a Customer's Asset Owner activity.

**Transmission Charge**

\$0.009155 per kWh for the gross Energy consumed at each IDR, netted by Premise (Tier 1, Tier 2, and Tier 3).

**Adjacent Affiliate Qualifying Facility Premise Transmission Charge**

\$0.002747 per kWh for the gross Energy transferred from a premise with behind the meter generation to an adjacent premise held under common ownership or by affiliates (as defined in Indiana Code § 23-1-43-1).

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**DETERMINATION OF DEMAND**

The Customer's Demand of electric Energy supplied shall be determined for each half-hour interval of the month and said demand in kW for each half-hour interval shall be two (2) times the number of kWhs recorded during each half-hour interval. The phrase "half-hour interval" shall mean the thirty (30) minute period beginning or ending on a numbered clock hour as indicated by the clock controlling the metering equipment.

The Customer's current integrated Demand shall be determined for each MISO settlement period for load as the total kWh recorded during that MISO settlement period multiplied by the ratio of 60 minutes to the total number of minutes in that MISO settlement period.

**DETERMINATION OF LAGGING kVAR**

The Customer's requirements in Lagging kVAR shall be determined for each half-hour interval of the month and shall be two (2) times the number of Lagging kVAR Hours recorded during each half-hour interval. No effect whatsoever shall be given hereunder to Customer's leading kVAR, if any.

**ADJUSTMENT FOR CUSTOMER'S PEAK HOURS LAGGING kVAR**

The number of kVAR shall be computed each month for a Power Factor of eighty-five percent (85%) Lagging using as the basis of said computation, the Customer's Maximum Demand for the month during the Peak Period hours thereof.

If the Customer's Maximum Peak Period Requirement in Lagging kVAR for the month is greater than the number of kVAR at a Power Factor of eighty-five percent (85%) Lagging, as determined above, an amount equal to the product of \$0.34 times said difference shall be added to the Customer's Bill.

If the Customer's Maximum Peak Period Requirement in Lagging kVAR for the month is less than the number of kVAR at a Power Factor of eighty-five percent (85%) Lagging, as determined above, an amount equal to the product of \$0.34 times said difference shall be deducted from the Customer's Bill.

The Customer agrees to control and limit Maximum Off-Peak (weekdays 22:00 – 06:00 CST, all weekend hours, and all hours during NERC holidays) Period Requirement in Lagging kVAR so that, as related to the Maximum Off-Peak Period kW Demand, it shall not exceed in ratio or numerical proportion the ratio of the Maximum Peak Period Requirement in Lagging kVAR and the Maximum Peak Period kW Demand; except that if such Maximum Off-Peak Period kW Demand is less than the Maximum Peak Period kW Demand, the Customer's Maximum Off-Peak Period Requirement in Lagging kVAR may equal the Customer's Maximum Peak Period Requirement in Lagging kVAR.

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**CUSTOMER LOAD INFORMATION**

If requested by the Company, the Customer shall cooperate with the Company by furnishing the Company in writing on or before the first day of July each year a statement of the Customer's estimates of the Customer's future load on the Company by months for a subsequent period of thirty (30) months.

The Customer shall also make a good faith effort to provide the Company in writing with an accurate hourly load forecast on a daily basis.

The Customer shall notify the Company in writing of any material increase in load no less than sixty (60) days prior to the addition of that load.

The Customer's dispatcher shall cooperate with the Company's dispatcher by furnishing, from time to time, such load information and operating schedules which will enable the Company to plan its generating operations.

The accuracy of the information herein called for is not guaranteed by the Customer and reliance thereon shall be at the sole risk of the Company.

Failure by the Customer to provide requested information on an ongoing basis may result in Customer being moved to another Rate Schedule upon ninety (90) days' notice from the Company to Customer.

**CUSTOMER'S FAILURE TO COMPLY WITH REQUESTED MISO CURTAILMENT**

A Customer is deemed to have failed to comply with a MISO Curtailment when the Customer's current integrated Demand, as measured by the meters installed by the Company (netted across aggregated Customer Premises, if applicable), has not decreased to a level of the sum of the Customer's specified Tier 1, firm Tier 2 and firm Tier 3 Contract Demands.

If a Customer fails to comply with a MISO Curtailment, the Customer shall be liable for any charges and/or penalties from any governmental agency(ies) having jurisdiction or duly applicable organization including MISO, FERC, NERC and ReliabilityFirst for failure to comply with a MISO Curtailment. Penalties and charges may be, but are not limited to, penalties associated with disqualification as a LMR to the extent such penalties are specifically invoked on the Company due to the failure of the Customer to comply with the Curtailment.



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**GENERAL TERMS AND CONDITIONS OF SERVICE**

**1. Contract**

Any Customer requesting service under this Rate Schedule shall enter into a written contract for an initial period of not less than five (5) Contract Years. The Customer maintains the ability to cancel the contract if the entire Premise is closing. For customers who are aggregating Premises, if one Premise closes, the Customer may modify its Tier 1 Contract Demand with 12 months' notice, but it may not go below 10,000 kW. For a Customer partially closing a Premise, the Customer may modify its Tier 1 Contract Demand with 12 months' notice, but it may not go below 10,000 kW. The Customer may increase the Tier 1 firm Contract Demand election with five (5) years' notice and a period of not less than five (5) Contract Years. On a quarterly basis, consistent with the MISO Commercial Model timing, a Customer may elect to move all, or a portion, of its election(s) under Tier 2 and Tier 3 between such.

Notwithstanding the foregoing, contracts under this Rate Schedule shall terminate in accordance with Rule 5.8 of the Company Rules.

**2. Default Schedule**

Notwithstanding the foregoing conditions of service under this Rate Schedule, service shall be subject to the provisions of Rule 5.9 of the Company Rules.

**3. Customer Disqualification**

Under this Rate Schedule and / or applicable Riders to this Rate Schedule, any Customer that is found to be engaging in activity that is determined to be a violation of market manipulation or antitrust rules / laws may be subject to disqualification from eligibility for Tier 3 of this Rate Schedule if any such activity disqualifies the Customer from meeting obligations set forth under this Rate Schedule. Penalties and charges may be, but are not limited to, penalties associated with disqualification as a LMR, any market damages, or private party damages. By taking service under this Rate Schedule, the Customer agrees to fully participate in any investigation into possible violation(s).

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Cancelling All Previously Approved Tariffs**

**RATE 831  
RATE FOR ELECTRIC SERVICE  
INDUSTRIAL POWER SERVICE - LARGE**

Sheet No. 13 of 13

**GENERAL TERMS AND CONDITIONS OF SERVICE (Continued)**

**3. Customer Disqualification (Continued)**

Any Customer that is disqualified from eligibility for service under Tier 3 service shall have all of its Tier 3 Contract Demand moved to Tier 2 with all of the Customer's Tier 2 Contract Demand, including any pre-existing Tier 2 Contract Demand of the Customer, covered with capacity through MISO's PRA and replacement capacity provisions within the MISO Tariff and may require Customer to procure replacement capacity or pay MISO capacity deficiency charges / penalties. The Customer will not be eligible for Tier 3 service and LMR registration for a period of five (5) years. After the five (5) year period, the Customer may be allowed to return to Tier 3 under this Rate Schedule or successor.

**RULES AND REGULATIONS**

Service hereunder shall be subject to the Company Rules, IURC Rules, and MISO Rules.

**Issued Date**  
\_\_\_/\_\_\_/2019

**Effective Date**  
6/30/2019

