JI Exhibit 1

STATE OF INDIANA

BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	**))))))))))))))))**	**CAUSE NO. 45253**

DIRECT TESTIMONY OF JONATHAN WALLACH

ON BEHALF OF

CITIZENS ACTION COALITION OF INDIANA, INC.,

INDIANA COMMUNITY ACTION ASSOCIATION,

AND

ENVIRONMENTAL WORKING GROUP

Resource Insight, Inc.

OCTOBER 30, 2019

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I. Introduction and Summary

Q: Please state your name, occupation, and business address.

A: My name is Jonathan F. Wallach. I am Vice President of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Please summarize your professional experience.

A: I have worked as a consultant to the electric power industry since 1981. From 1981 to 1986, I was a Research Associate at Energy Systems Research Group. In 1987 and 1988, I was an independent consultant. From 1989 to 1990, I was a Senior Analyst at Komanoff Energy Associates. I have been in my current position at Resource Insight since 1990.

Over the past four decades, I have advised and testified on behalf of clients on a wide range of economic, planning, and policy issues relating to the regulation of electric utilities, including: electric-utility restructuring; wholesale-power market design and operations; transmission pricing and policy; market-price forecasting; market valuation of generating assets and purchase contracts; power-procurement strategies; risk assessment and mitigation; integrated resource planning; mergers and acquisitions; cost allocation and rate design; and energy-efficiency program design and planning.

My resume is attached as Attachment JFW-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have sponsored expert testimony in more than 90 state, provincial, and federal proceedings in the U.S. and Canada, including before the Indiana Utility Regulatory Commission ("the Commission") in Cause Nos. 44967, 45029, 45159, and 45235. I include a detailed list of my previous testimony in Attachment JFW-1.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Citizens Action Coalition of Indiana, Inc. ("CAC"), Indiana Community Action Association ("INCAA"), and Environmental Working Group ("EWG") (collectively, "Joint Intervenors" or "JI").

Q: Are you sponsoring any attachments?

A: Yes. I am sponsoring the following attachments:

- Attachment JFW-1: Resume of Jonathan Wallach, Resource Insight, Inc.
- Attachment JFW-2: Verified Statement of Jonathan Wallach supporting Joint Motion to Amend Procedural Schedule, for Appropriate Relief, and for Expedited Briefing (filed October 15, 2019)
- Attachment JFW-3: CAC Data Request Sets 19 and 20 to DEI
- Attachment JFW-4: National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, 38-39 and 52-53 (January, 1992)
- Attachment JFW-5: DEI Response to CAC Data Request 12-4(d)
- Attachment JFW-6: National Association of Regulatory Utility Commissioners, *Distributed Energy Resources Rate Design and Compensation*, 118 (November 2016)
- Attachment JFW-7: James C. Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 331, 334, and 336 (1961)
- Attachment JFW-8: Alfred E. Kahn, *The Economics of Regulation*, The MIT Press, 85 (1988)
- Attachment JFW-9: Paul J. Garfield and Wallace F. Lovejoy, *Public Utility Economics*, Prentice-Hall, Inc., 155-156 (1964)
- Attachment JFW-10: CAC Attachment 12.14B to DEI Response to CAC Data Request 12-14
- Attachment JFW-11: Citations to Marginal-Price Elasticity Studies

Q: What is the purpose of your testimony?

A: On July 2, 2019, Duke Energy Indiana, LLC ("DEI" or "the Company") filed a petition (including supporting direct testimony) with the Commission for authority to increase electric rates. On September 9, 2019, DEI filed revised direct testimony and exhibits, along with revisions to the Minimum Standard Filing Requirements ("MSFR").[1]

My testimony addresses the Company's proposals to:

- Allocate among the various retail rate classes the forecasted revenue deficiency for the 2020 test year based on the results of a cost-of-service study ("COSS"), as discussed in direct testimony by DEI witness Maria T. Diaz.
- Increase the monthly connection charge and modify the declining-block rate structure for volumetric energy rates for residential customers, as described by DEI witness Jeffrey R. Bailey.[2]
- Implement a Revenue Decoupling Mechanism ("RDM") for residential and small-commercial customers, as discussed in direct testimony by DEI witnesses Brian P. Davey, Daniel G. Hansen, and Robert E. Hevert.

Q: Were you able to complete your analyses of these proposals by the filing deadline for your direct testimony?

A: No. As described in detail in a motion filed on October 15, 2019 and subsequent reply by the Indiana Office of Utility Consumer Counsel ("OUCC"), CAC, and other intervenors in this proceeding ("Joint Motion"), the Company's petition was incomplete, poorly documented, and internally

[1] The Company subsequently filed corrections to these revised MSFRs on September 26, 2019.

[2] By "residential", I mean in the context of cost allocation and rate design those customers taking service under either Rate RS (Residential and Farm Electric Service) or Contract Rider No. 6.3 (Optional High Efficiency Residential Service). However, I do not specifically address the Company's proposal regarding the discounted energy rate applicable to residential customers taking service under Contract Rider No. 6.3.

inconsistent.[3] As discussed in the Joint Motion, CAC first contacted DEI on September 6, 2019 regarding major deficiencies in the Company's petition. Since that time, CAC, OUCC, and other intervenors have devoted an inordinate amount of time and resources attempting to remedy these flaws through multiple conference calls with DEI and informal data requests.[4] At this time, this effort is ongoing.[5]

Consequently, my analysis, findings, and conclusions at this point are preliminary and subject to correction, revision, and additional analysis and commentary. I therefore expressly reserve the right to supplement, revise, and correct my testimony at a later date.

Q: Please summarize your findings and conclusions with regard to DEI's proposal for allocating the requested revenue increase.

A: The Commission should reject the Company's proposal for allocating the requested revenue deficiency because it relies solely on the results of a cost-of-service study that does not allocate costs to customer classes in a manner that reasonably reflects each class's responsibility for such costs. Correcting just for these misallocations in the Company's COSS would reduce the allocation of the requested revenue requirement to the residential class by about $104 million.

Furthermore, the Commission should reject the Company's proposal for reducing the current "subsidy" to the residential class. After so many years

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[3] *See* Joint Movants' Joint Motion to Amend Procedural Schedule, for Appropriate Relief, and for Expedited Brief and subsequent Reply, which are incorporated here by reference.

[4] Please see my affidavit supporting the Motion attached to this testimony (Attachment JFW-2).

[5] *See* CAC Data Request Sets 19 and 20 to DEI (Attachment JFW-3).

without a rate case, residential customers are facing overwhelming rate shock even without the increase necessary to reduce the alleged current "subsidy". Now is simply not the time to try to remedy the subsidies of the past.

Q: Please summarize your findings and recommendations with regard to DEI's proposal to increase the residential connection charge.

A: The Company proposes two different connection charges depending on whether the Commission approves the proposed Revenue Decoupling Mechanism. Specifically, in the event that the Commission approves the proposed RDM, DEI proposes to set the residential connection charge at $9.80 per residential bill, which is the Company's estimate of the cost to connect a residential customer. However, if the Commission rejects the RDM proposal, DEI proposes to set the residential connection charge at $10.54 per residential bill.

Regardless of whether the proposed RDM is approved, the Commission should reject both of the Company's proposals for setting the residential connection charge. A $9.80 residential connection charge would recover $0.76, or about 8%, more than the actual cost to connect a residential customer. In other words, the Company's estimate of residential connection cost overstates the actual cost to serve by about 8%.

On the other hand, by the Company's own admission, a $10.54 residential connection charge would exceed the Company's (overstated) estimate of the cost to serve. Consequently, the Company's proposal for a $10.54 residential connection charge runs contrary to long-standing principles for designing cost-based rates since it would inappropriately shift recovery of demand-related costs from the volumetric energy rate to the fixed connection charge. As explained in more detail below, the Company's proposal to recover demand-related costs through the residential connection charge would:

- Lead to subsidization of high-usage residential customers' costs by low-usage customers, and thereby inequitably increase bills for the Company's low-usage residential customers.
- Dampen price signals to consumers for controlling their bills through conservation or investments in energy efficiency or distributed renewable generation.

Consequently, the Commission should reject both of the Company's proposals for the residential connection charge. Instead, I recommend that the residential connection charge be maintained at the current rate of $9.01 per residential bill, reflecting the actual cost to connect a residential customer. Consistent with long-standing cost-causation and rate-design principles, a monthly connection charge of $9.01 would provide for the recovery of the cost of meters, service drops, and customer services required to connect a residential customer.

Q: Please summarize your findings and recommendations with regard to the design of volumetric energy rates for residential customers.

A: The Company proposes two different declining-block rate structures for residential energy rates depending on whether the Commission approves the proposed Revenue Decoupling Mechanism. I have not been able to complete my analysis of the Company's proposals for residential energy rates at this time due to extensive delays caused by inconsistencies in the Company's rate design workpapers and by the Company's failure to-date to fully document its derivation of the proposed energy rates, as explained in Joint Movants' Motion and subsequent Reply. However, my preliminary analysis indicates that DEI lacks a reasonable basis for continuing to employ a declining-block rate structure for residential energy rates. The declining-block rate structures proposed by DEI in either the with-RDM or without-RDM scenarios would recover demand-related costs at a higher rate in the first energy block than in the second and third blocks, and thereby would further dampen energy price signals and promote inefficient customer behavior.

I will address the Company's proposal regarding residential energy rates in supplemental testimony.

Q: Please summarize your findings and recommendations with regard to the Company's proposal to implement a Revenue Decoupling Mechanism for residential and small-commercial customers.

A: I have not been able to complete my analysis of the Company's proposal for a Revenue Decoupling Mechanism at this time due to outstanding issues regarding the Company's forecast of residential billing determinants for the 2020 test year.[6] However, my preliminary analysis indicates that the proposed RDM would not provide any tangible economic benefits to residential customers. To the contrary, over the proposed five-year RDM implementation period, residential customers would be expected to pay more for electric service with than without the RDM. In other words, the proposed RDM would be expected to not only ensure, but also enhance revenue recovery for DEI and its shareholders between rate cases.

I will address the Company's RDM proposal in detail in supplemental testimony once the outstanding issues regarding the Company's forecast of residential billing determinants for the 2020 test year are resolved.

[6] *See* CAC Data Request Sets 19 and 20 (Attachment JFW-3). *See also* Joint Movants' Motion and subsequent Reply.

Q: How is the rest of your testimony organized?

A: In Section II, I describe how the Company's proposal for allocating the test-year revenue deficiency relies on a COSS that misallocates production and distribution plant costs. In Section III, I explain how DEI's proposal to increase the residential connection charge violates long-standing principles of cost-based rate design, would give rise to unreasonable cost subsidization within the residential class, and would dampen energy price signals. In Section IV, I address the Company's proposal to maintain a declining-block rate structure for residential volumetric energy rates. In Section V, I address DEI's proposal to implement a Revenue Decoupling Mechanism for residential and small-commercial customers. Finally, I provide my conclusions and recommendations in Section VI.

II. Revenue Allocation

Q: Please describe the Company's requested revenue increase.

A: The Company is requesting that electric retail base rates be increased on average by 15.7% in order to recover an expected revenue deficiency of about $394.6 million in the 2020 test year.[7] Of the total $394.6 million requested base revenue increase, DEI proposes to allocate about $191.7 million to residential customers. This amount represents a 19.4% increase over residential test-year revenues under current rates.[8]

[7] MSFR Workpaper COSS24-MTD. The $394.6 million amount is net of utility receipts tax revenue, which DEI proposes to recover through a separate surcharge on customers' bills.

[8] *Id.*

Q: What is the basis for the Company's proposed allocation of the requested base revenue increase to the residential class?

A: According to DEI witness Maria T. Diaz, the Company's COSS served as the basis for its revenue allocation proposal. Specifically, the Company's COSS indicates that residential base revenues would have to be increased by about \$283.7 million, or about 28.7%, to achieve the requested rate of return.[9] Of that total increase, the Company's COSS indicates that about \$96.9 million represents the increase required to achieve the system average rate of return under current rates.[10] In other words, the Company's COSS indicates that the residential class is currently under-earning relative to the system average achieved rate of return and that the current "subsidy" amounts to \$96.9 million. According to Ms. Diaz, DEI proposes to increase residential base revenues to eliminate 5.1% of this current subsidy.[11]

Q: What is the purpose of a cost of service study?

A: The primary purpose of a cost of service study is to allocate a utility's total revenue requirements to individual customers or rate classes in a manner that reasonably reflects each class's responsibility for such revenue requirements. In other words, the primary purpose of a cost of service study is to attribute costs to customer classes based on how those classes cause such costs to be incurred.

Q: Please describe how the Company's COSS allocates total-system retail revenue requirements to customer classes.

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[9] Calculated based on data provided in MSFR Workpaper COSS24-MTD and COSS20-MTD.

[10] MSFR Workpaper COSS20-MTD.

[11] *Revised Direct Testimony of Maria T. Diaz*, Cause No. 45253, 3 (September 9, 2019) [Hereinafter "Revised Diaz Direct"].

A: In order to allocate costs to customer classes, the COSS first separates total costs into production, transmission, distribution, and customer functions. Costs in each function are then classified as energy-, demand-, or customer-related based on whether costs are considered to be "caused" by energy sales, peak demand, or the number of customers, respectively. Finally, costs classified as either energy-, demand-, or customer-related are allocated to customer classes in proportion to each class's contribution to total-system energy sales, peak demand, or number of customers, respectively.[12]

Q: Does the Company's COSS reasonably allocate test-year revenue requirements?

A: No. The Company's COSS does not allocate costs to customer classes in a manner that reasonably reflects each class's responsibility for such costs. In particular, the COSS misallocates production and distribution plant costs.

Q: How does the Company's COSS misallocate production plant costs?

A: As described in detail below, the Company's COSS over-allocates production plant costs to classes with low load factors by inappropriately classifying all such costs as demand-related.[13] The COSS then compounds this error by allocating demand-related plant costs based on each class's contribution to system peak in the four months of the year with the highest system peak demands ("4CP allocator"), rather than based on the contribution to system peak throughout the year ("12CP allocator").

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[12] *Id.*, 7-10.

[13] Load factor is defined as the ratio of average demand to peak demand, where average demand is annual energy requirements divided by 8760 (i.e., the number of hours in a year).

Q: How does the Company's COSS misallocate distribution plant costs?

A: As discussed below, the Company's COSS over-allocates distribution plant costs to low-coincidence classes by allocating demand-related distribution plant costs on the basis of customer maximum demand, rather than based on customer demand coincident with class peaks.[14]

Q: Have you estimated the impact of these errors on the allocation of 2020 test-year revenue requirements to the residential class?

A: Yes. At CAC's request, DEI developed a spreadsheet version of its proprietary COSS software model and then modified this COSS spreadsheet model to correct for these misallocations.[15] Correcting for these misallocations reduces the allocation of 2020 test-year revenue requirements to the residential class by $104 million at an equalized rate of return. With these corrections, residential base revenues would need to be increased by about 18.2% to achieve the requested rate of return. In other words, where the Company's COSS indicates that a 19.4% increase in residential revenues would achieve a 5.1% reduction in alleged current subsidies, this corrected COSS indicates that an 18.2% increase in residential revenues *would completely eliminate* alleged current subsidies.

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[14] Coincidence is defined as the ratio of the sum of individual customer demands at the time of (i.e., coincident with) the class maximum demand to the sum of the individual customer maximum demands (regardless of when such customer maximum demands occur).

[15] As noted in Joint Movants' Reply, CAC asked about how to make intervenor-requested changes to the COSS spreadsheet model throughout September and October. After several weeks of discussion, the Company provided the intervenor-requested modified version of its COSS spreadsheet model to CAC and other parties on October 22, 2019 (labeled by the Company as "DEI COSS Tie Out Version 4 MODEL RUN 3 10-22-19"). This spreadsheet, which DEI has labeled as confidential, will be provided to the Commission in my workpaper submission.

On the other hand, this corrected COSS indicates that residential base revenues would need to be increased by only 16.8% if there were no reduction to the alleged current subsidy.

A. Misclassification of Production Plant Costs

Q: Why is it inappropriate to classify all production plant costs as demand-related?

A: It is inappropriate because it is inconsistent with cost-causation. The Company's COSS classifies production plant costs as if such costs were incurred solely for the purposes of meeting system reliability requirements, and not at all for the purposes of minimizing the cost of meeting energy requirements. However, under typical generation expansion planning practices, plant investment choices are driven by both reliability and energy requirements. As explained in NARUC's *Electric Utility Cost Allocation Manual*:

> Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability, loss of load hours, reserve margin, or expected unserved energy; and (2) that the utility's energy load or load duration curve is a major indicator of the type of plant needed. The type of plant installed determines the cost of the additional capacity. This approach is well represented among the energy weighting methods of cost allocation.[16]

[16] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, 38-39 (January, 1992) (Attachment JFW-4).

From a cost-causation perspective, investments in peaking plant are appropriately classified as demand-related, since peaking units typically would be the least-cost generation option for meeting an increase in peak demand and planning reserve requirements. On the other hand, baseload or intermediate plant costs *in excess of peaking plant costs* (so-called "capitalized energy" costs) should be classified as energy-related, since these incremental costs are incurred to minimize the total cost of meeting an increase in energy requirements.

The Company's COSS misclassifies these capitalized energy costs as demand-related. As a result, the Company's COSS over-allocates capitalized energy costs to the residential class and under-allocates such costs to the industrial classes since the residential class has a lower load factor than the industrial classes.[17]

Q: Are there other classification methods that would classify the Company's production plant costs in a manner that reasonably reflects cost causation?

A: Yes. For example, the Equivalent Peaker classification method classifies production plant costs in a manner that reasonably reflects investment decision-making under typical generation expansion planning practices, as described above. According to the *Electric Utility Cost Allocation Manual*:

[17] A customer class with a low load factor (relative to other classes) will be allocated a greater percentage of demand-related costs than that of energy-related costs because that class's percentage contribution to total system demand is larger than its contribution to total system energy requirement.

> Equivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added….
>
> The premises of this and other peaker methods are: (1) that increases in peak demand require the addition of peaking capacity only; and (2) that utilities incur the costs of more expensive intermediate and baseload units because of the additional energy loads they must serve. Thus, the cost of peaking capacity can properly be regarded as peak demand-related and classified as demand-related in the cost of service study. The difference between the utility's total cost for production plant and the cost of peaking capacity is caused by the energy loads to be served by the utility and is classified as energy-related in the cost of service study.[18]

Q: Have you reclassified the Company's production plant costs using the Equivalent Peaker method?

A: Yes. For this analysis, I estimated the demand- and energy-related portions of the Company's production plant costs based on data reported in the Company's FERC Form 1 report for 2018.[19] I calculated the demand-related portion of total plant costs for the Company's generation portfolio as the product of: (1) total plant capacity of the Company's generation portfolio; and (2) the average plant cost per kilowatt of plant capacity for the Company's gas turbines. In other words, the demand-related portion of total plant costs is what plant costs would have amounted to if the Company's generation capacity were priced at the average cost per kilowatt for its gas turbines. The energy-related (or capitalized energy) portion is then the excess of total plant costs over the demand-related portion of total plant costs. Using this approach, I estimate that

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[18] *Electric Utility Cost Allocation Manual*, 52-53 (Attachment JFW-4).

[19] The workpaper for my Equivalent Peaker analysis will be provided to the Commission in my workpaper submission.

30% of the Company's production plant costs are demand-related and about 70% are energy-related.

B. Misallocation of Demand-Related Production Plant Costs

Q: How are demand-related production plant costs allocated to customer classes in the Company's COSS?

A: The Company's COSS uses a 4CP allocator, which allocates such costs in proportion to each class's contribution to system peak demand in the four months of the year with the highest system peaks. Specifically, with the 4CP allocator, each class's percentage share of total demand-related production plant costs is calculated as the ratio of: (1) the average of the class's demand at time of system peak in the months of January, June, August, and September; and (2) the average of system peak demands in those same four months.

Q: Is the Company's use of the 4CP allocator in the COSS a deviation from past practice?

A: Yes. According to DEI witness Diaz, the Company's long-standing practice prior to this proceeding has been to allocate demand-related production plant costs in proportion to each class's contribution to the average of the 12 monthly system peaks. In fact, according to Ms. Diaz, the Company's use of the 12CP allocator "was approved at least 13 times since 1971 in the Company's retail rate case proceedings".[20]

Q: Why did DEI abandon long-standing practice in this proceeding?

A: According to Ms. Diaz, DEI agreed as part of a 2005 settlement agreement in Cause No. 42873 to employ a 4CP allocator in the next rate case that followed

[20] Revised Diaz Direct, 6.

that Cause.[21] This current proceeding is the first DEI rate case since the Commission approved the settlement agreement in Cause No. 42873.

Q: Did the Commission approve the use of the 4CP allocator as part of its approval of the settlement agreement in Cause No. 42873?

A: No. To the contrary, the Commission explicitly declined to rule on the reasonableness of the 4CP allocator:

> While the Settlement Agreement sets forth an agreed upon framework under which certain parties intend to address rate design issues in PSI's next rate case, we agree with Mr. Fagan that as the issue is sufficiently unrelated to the matter presented to us for approval in this Cause it is not necessary or appropriate for the Commission to affirm this understanding and approach as part of this proceeding.[22]

Q: Which of these two allocators, 4CP or 12CP, most reasonably reflects each class's responsibility for demand-related production plant costs?

A: The 12CP allocator more reasonably reflects the drivers of the Company's investments in demand-related production costs and therefore allocates such costs more consistently with cost-causation principles.

The 4CP allocator allocates demand-related production plant costs on the basis of each class's contribution to system peaks in the four months of the year with the highest system peak demands. As discussed above, demand-related production plant costs are incurred for the purposes of meeting reserve requirements. Thus, the 4CP allocator allocates demand-related production plant costs consistent with the notion that the Company's planning reserve requirements are driven solely by the four highest monthly system peaks in the year.

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[21] *Id.*

[22] IURC Final Order, Cause No. 42873, 19 (March 15, 2006).

In contrast, the 12CP allocator allocates demand-related production plant costs on the basis of each class's contribution to the twelve monthly system peaks. Thus, the 12CP allocator allocates demand-related production plant costs as if the Company's planning reserve requirements are driven by system peaks in all months of the year.

In reality, the Midcontinent Independent System Operator ("MISO") determines the Company's annual reserve requirements based on demand throughout the year, not just on peak demand in the four months with the highest peak demands. Specifically, MISO determines the amount of capacity required for planning reserve based on the results of a loss of load probability ("LOLP") analysis that considers the daily contribution of the Company's demand to annual loss of load expectation ("LOLE"). Although lower than demands in the peak demand months, demands in non-peak months can also contribute to annual LOLE and thus to system reserve requirements at times when margins between available capacity and demand are tight. For example, the scheduling of plant maintenance during low-demand shoulder months can reduce capacity margins during peak periods in those shoulder months and thus increase annual LOLE and reserve requirements.

Thus, the Company's investments in capacity to meet reserve requirements are driven by demand in every month, not just by the demands in peak months. Consequently, a 12CP allocator is a more reasonable measure of each class's contribution to the need for new reserve capacity than a 4CP allocator.

C. Misallocation of Distribution Plant Costs

Q: How does the Company's COSS allocate the costs of distribution poles, conductors, and transformers?

A: The Company's COSS allocates the costs of secondary poles, conductors, and transformers on the basis of each class's non-coincident peak demand ("NCP"). Class non-coincident peak demand in any month is derived by summing individual customers' maximum demand during the month. The NCP allocator derives each class's percentage share of secondary distribution plant costs calculated as the ratio of: (1) the average of the class's monthly NCPs over the year; and (2) the average over the year of the sum of all classes' NCPs in each month.

The Company's COSS allocates the costs of primary poles and conductors based on a weighted average of each class's NCP and diversified peak demand. Class diversified peak demand in any month is derived by summing individual customers' demand at the time of the class peak during that month. In other words, class diversified peak demand is simply the maximum demand for the class as a whole.

Q: Does the NCP allocator reasonably reflect cost-causation?

A: No. The NCP allocator does not account for the effect of load diversity on distribution equipment loading and thus does not reasonably reflect the drivers of the Company's distribution plant investment. By failing to account for load diversity, the NCP allocator likely overstates the residential class's contribution to distribution costs and thus over-allocates such costs to the residential class.

Q: How does load diversity affect the sizing of distribution plant?

A: Residential customers reach their individual maximum demands on different days and in different hours of the day. This diversity of demand among a group of residential customers served by a piece of distribution equipment results in a group peak demand that is lower than the sum of customers' individual maximum demands. As is typical for electric utilities, DEI sizes distribution plant to meet the group peak, not to meet the sum of customers' individual maximum demands.[23]

Q: Why does the NCP allocator over-allocate distribution plant costs to the residential class?

A: The NCP allocator over-allocates costs to the residential class because it does not account for the effect of load diversity on equipment sizing and thus on equipment cost.

Specifically, the NCP allocator does not account for the fact that distribution equipment serving many small residential customers can be smaller (and less expensive) than equipment that serves fewer large industrial customers, even when the sum of the residential maximum demands is equal to the sum of industrial maximum demands. As the number of customers served by distribution equipment increases, so too does the diversity of maximum hourly demands among those customers. And as the diversity of maximum demands increases, so too does the variance between the sum of individual customers' maximum hourly demands (i.e., group NCP) and the maximum demand for the group as a whole (i.e., group diversified demand.) By not accounting for load diversity, the NCP allocator allocates cost to classes

[23] *See, e.g.*, DEI Response to CAC Data Request 12-4(d) (Attachment JFW-5).

as if the sizing and cost of distribution equipment is driven by each class's NCP rather than by the class's diversified demand on the equipment.

Q: How should distribution plant costs be allocated?

A: In order to reasonably account for the effect of load diversity, distribution plant costs should be allocated on the basis of each class's diversified peak demand ("DIV"). Specifically, each class's allocated share of distribution plant costs should be derived as the ratio of: (1) the average of the class's monthly DIVs over the year; and (2) the average over the year of the sum of all classes' DIVs in each month.

III. Residential Connection Charge

A. DEI's Proposal to Increase the Residential Connection Charge

Q: What is a connection charge?

A: A connection charge is a fixed fee charged to each customer on their monthly bill regardless of the customer's energy usage during that month.

Q: What is the Company's proposal with respect to the monthly fixed connection charge for residential customers?

A: The Company proposes two different connection charges depending on whether the Commission approves the proposed Revenue Decoupling Mechanism ("RDM"). In the event that the Commission approves the proposed RDM, DEI proposes to increase the residential connection charge from $9.01 to $9.80 per residential bill.[24] The proposed $0.79 increase represents a 9% increase over the current connection charge.

[24] *Revised Direct Testimony of Jeffrey R. Bailey*, Cause No. 45253, 7 (September 9, 2019) [Hereinafter "Revised Bailey Direct"].

If, however, the Commission rejects the RDM proposal, DEI proposes to set the residential connection charge at $10.54 per residential bill.[25] The proposed $1.53 increase in this case represents a 17% increase over the current connection charge.

Q: How did DEI derive the residential connection charges proposed for the with- and without-RDM scenarios?

A: According to Company witness Jeffrey R. Bailey, DEI set the proposed with-RDM residential connection charge to recover costs classified as customer-related and allocated to the residential class in the Company's COSS. These costs include the costs for meters, service drops, metering and billing, other customer services, and bad debt.[26]

The Company has not explained how it derived its proposed rate for the without-RDM residential connection charge. However, because the without-RDM connection charge would be set at a higher rate than the with-RDM connection charge, the proposed without-RDM residential connection charge would inappropriately recover costs that are classified as demand-related in the Company's COSS as explained below.

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[25] *Id.*

[26] *Id.*, 6.

B. *DEI's Proposals for the Residential Connection Charge Violates Principles of Cost-Based Rate Design*

Q: What are the relevant considerations in designing cost-based rates for residential customers?

A: As the Commission recognized in Cause No. 44576, the primary challenge in rate design is to reflect the costs that customers impose on the system, both to encourage them to use utility resources responsibly and to share costs fairly:

> Cost recovery design alignment with cost causation principles sends efficient price signals to customers, allowing customers to make informed decisions regarding their consumption of the service being provided.[27]

Accordingly, fixed connection charges should reflect the fact that each customer contributes equally to certain types of costs (e.g., meter costs) regardless of that customer's energy usage. Volumetric energy rates, on the other hand, recognize that customers of different sizes and load profiles contribute to other types of costs (e.g., generation plant costs) at different levels. If usage-driven costs are inappropriately collected through fixed connection charges, then customers will have reduced incentives to control their bills through conservation or investments in energy efficiency or distributed renewable generation.[28]

Q: Given these considerations, what categories of costs are appropriately recovered through the volumetric energy rate?

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[27] IURC Final Order, Cause No. 44576, 72 (March 16, 2016).

[28] National Association of Regulatory Utility Commissioners, *Distributed Energy Resources Rate Design and Compensation*, 118 (November 2016), available at https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0 (excerpt included as Attachment JFW-6).

A: In order to provide efficient price signals, volumetric energy rates should be set at levels that recover those categories of costs that tend to increase with customer usage over the long run, including plant, fuel, and O&M costs for the production, transmission, and distribution functions, along with certain customer-service costs that tend to vary with usage such as uncollectible costs.[29] In other words, volumetric energy rates should reflect long-run marginal costs.

As James Bonbright explains in his seminal text *Principles of Public Utility Rates*:

> In view of the above-noted importance attached to existing utility rates as indicators of rates to be charged over a somewhat extended period in the future, one may argue with much force that the cost relationships to which rates should be adjusted are not those highly volatile relationships reflected by short-run marginal costs but rather those relatively stable relationships represented by long-run marginal costs. The advantages of the relatively stable and predictable rates in permitting consumers to make more rational long-run provisions for the use of utility services may well more than offset the admitted advantages of the more flexible rates that would be required in order to promote the best available use of the existing capacity of a utility plant.[30]
>
> I conclude this chapter with the opinion, which would probably represent the majority position among economists, that, as setting a general basis of minimum public utility rates and of rate relationships, the more significant marginal or incremental costs are those of a relatively long-run variety – of a variety which treats even capital costs or “capacity costs” as variable costs.[31]

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[29] Uncollectible costs are the billed amounts not recovered from customers as a result of those customers’ non-payment of all or a portion of their monthly bills.

[30] James C. Bonbright, *Principles of Public Utility Rates*. Columbia University Press, 334 (1961), available at media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf (excerpt included as Attachment JFW-7).

[31] *Id.*, 336.

Almost three decades later, Alfred Kahn affirmed Bonbright's opinion in his text, *The Economics of Regulation*:

> … the practically achievable benchmark for efficient pricing is more likely to be a type of average long-run incremental cost, computed for a large, expected incremental block of sales, instead of SRMC [short-run marginal cost] ….[32]

Q: Which costs are appropriately recovered through the fixed connection charge?

A: In contrast to the volumetric energy rate, the fixed connection charge is intended to reflect the cost to connect a customer who uses very little or zero energy to the distribution system. Such "customer connection costs" are generally limited to plant and maintenance costs for a service drop and meter, along with meter-reading, billing, and other customer-service expenses. As Bonbright explains:

> But this twofold distinction [between demand and energy in rate design] overlooks the fact that a material part of the operating and capital costs of utility business is more directly and more closely related to the number of customers than to energy consumption on the one hand or maximum kilowatt demand on the other hand. The most obvious examples of these so-called customer costs are the expenses associated with metering and billing.[33]

In their text, *Public Utility Economics*, economists Paul Garfield and Wallace Lovejoy also describe which costs are truly customer-related and therefore appropriately recovered through the fixed connection charge:

[32] Alfred E. Kahn, *The Economics of Regulation*, The MIT Press, 85 (1988) (excerpt included as Attachment JFW-8).

[33] Bonbright, *op. cit.*, 311 (excerpt included as Attachment JFW-7).

> The purpose of both the connection charge and the minimum charge is to cover at least some of the costs incurred by the utility whether or not the customer uses energy in a particular month. For small customers under the block meter-rate schedule, a charge of this kind is intended to cover the expenses relating to meter service and maintenance, meter reading, accounting and collecting, return on the investment in meters and the service lines connecting the customer's premises to the distribution system, and others. Such expenses as these represent as a minimum the "readiness-to-serve" expenses incurred by the utility on behalf of each customer.[34]

More recently, Severin Borenstein restated these principles for designing cost-based fixed connection charges as follows:

> When having one more customer on the system raises the utility's costs regardless of how much the customer uses – for instance, for metering, billing, and maintaining the line from the distribution system to the house – then a fixed charge to reflect that additional fixed cost the customer imposes on the system makes perfect economic sense. The idea that each household has to cover its customer-specific fixed costs also has obvious appeal on ground of fairness or equity.[35]

Q: Are either of the Company's proposals for the residential connection charge consistent with these long-standing principles of cost-based rate design?

A: No. Contrary to these principles, DEI proposes to recover through the with-RDM fixed connection charge not just customer connection costs – i.e., the costs for meters, service drops, and customer services – but also uncollectible costs. For the without-RDM residential connection charge, DEI proposes to recover both uncollectible costs and a portion of the costs classified as

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[34] Paul J. Garfield and Wallace F. Lovejoy, *Public Utility Economics*, Prentice-Hall, Inc., 155-156 (1964) (excerpt included as Attachment JFW-9).

[35] Severin Borenstein, "What's So Great About Fixed Charges?" (2014), available at https://energyathaas.wordpress.com/2014/11/03/whats-so-great-about-fixed-charges/.

demand-related and allocated to the residential class under the Company's COSS in addition to minimum connection costs.

Q: Why is the Company's proposal to recover uncollectible costs through the residential connection charge inconsistent with cost-based rate design?

A: Uncollectible costs tend to vary with revenues and thus with usage. Thus, as discussed above, such costs are appropriately recovered through the volumetric energy rate.

Q: Is it reasonable to recover demand-related costs through the fixed connection charge, as the Company proposes for the without-RDM residential connection charge?

A: No. As discussed in detail below, the Company's proposal to recover more than customer connection cost through the residential connection charge would give rise to cost subsidization within the residential class and would dampen energy price signals to consumers for controlling their bills through conservation or investments in energy efficiency or distributed renewable generation.

Q: Have you estimated the cost to connect a residential customer based on the results of the Company's COSS?

A: Yes. As shown in Table 1 below, I estimate a residential cost of connection of $9.04 per residential per bill.

Q: How did you derive your estimate of the cost to connect a residential customer to the distribution grid?

A: The Company's COSS allocates to the residential class about $88.4 million in customer-related costs.[36] I then adjusted this total in order to remove

[36] Petitioner's Exhibit 7-H (MTD), Schedule 1.

uncollectible costs for the reasons discussed above.[37] Dividing the net amount of $81.6 million by the number of residential bills yields a connection cost of $9.04 per residential bill.[38]

Table 1: Derivation of the Cost to Connect a Residential Customer

	Residential Cost	**Residential Bills**	**Cost per Bill**
Customer-Related Cost	$88,449,267	9,025,558	$9.80
Less			
Uncollectible Expense	$(6,817,390)	9,025,558	$(0.76)
Total	$81,631,877		$9.04

Q: What accounts for the $1.50 difference between your $9.04 estimate for the cost to connect a residential customer and the $10.54 without-RDM fixed connection charge proposed by DEI?

A: As shown above in Table 1, $0.76 of the $1.50 difference between my $9.04 customer connection cost and the $10.54 without-RDM connection charge proposed by DEI represents load-varying uncollectible costs that should be recovered through volumetric energy rates. The remaining $0.74 difference represents costs classified as demand-related in the Company's COSS that would be inappropriately recovered through the fixed connection charge under the Company's without-RDM proposal. As discussed below, this shift in recovery of load-varying and demand-related costs from the volumetric energy rate to the fixed connection charge would give rise to cost subsidization within

[37] The Company provided its estimate of uncollectible costs allocated to the residential class in the Company's COSS in CAC Attachment 12.14B to DEI Response to CAC Data Request 12-14 (Attachment JFW-10).

[38] The number of residential bills is provided in Petitioner's Exhibit 7-H (MTD), Schedule 1.

the residential class and would dampen energy price signals to consumers for controlling their bills through conservation or investments in energy efficiency or distributed renewable generation.

C. DEI's Proposal for the Residential Connection Charge Would Lead to Intra-Class Cost Subsidization

Q: How would the Company's proposal to increase the residential connection charge cause intra-class subsidization?

A: As discussed above, DEI's proposal to increase the residential connection charge in the without-RDM scenario would shift recovery of both load-varying and demand-related costs from the volumetric energy rate to the fixed connection charge. Such load-varying or demand-related costs are driven by residential load and are therefore appropriately recovered from residential customers in proportion to their contribution to total load. To the extent that load-varying or demand-related costs are recovered at a fixed rate through the residential connection charge rather than at a volumetric rate through the energy charge, residential customers with below-average usage would bear a disproportionate share of demand-related costs and consequently subsidize customers with above-average usage. In this case, a residential customer with below-average usage will pay more, and a residential customer with above average-usage will pay less, than their fair share of such costs.

Q: What is the extent of the intra-class subsidization under the Company's proposal for the without-RDM residential fixed connection charge of $10.54?

A: As explained above, the $1.50 difference between customer connection cost and the without-RDM residential connection charge proposed by DEI represents load-varying or demand-related costs that would be inappropriately recovered from each residential customer every month through a fixed charge on the customer's bill. As indicated in Table 1 above, DEI estimates about 9.0 million residential bills in the test year. This means that about $13.5 million of load-varying or demand-related costs would be recovered annually through the residential fixed connection charge under the Company's proposal for the without-RDM scenario.[39]

If the load-varying and demand-related costs recovered through the residential fixed connection charge under the Company's proposal for the without-RDM scenario were instead recovered through the volumetric energy rate (as I propose), each residential customer would contribute to recovery of these costs in proportion to their usage. The Company estimates residential sales in the test year of about 8.7 million megawatt-hours.[40] Therefore, if the $13.5 million of load-varying or demand-related costs continued to be recovered through the volumetric energy rate rather than through the fixed connection charge, they would be charged at a rate of 0.16 cents per kilowatt-hour ("¢/kWh").[41] In this case, a residential customer with below-average monthly usage of 500 kWh would contribute about $9 per year toward recovery of the $13.5 million of load-varying or demand-related costs while a customer with above-average monthly usage of 1,500 kWh would contribute

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[39] The $13.5 million result is derived by taking the product of the annual number of residential bills (9.0 million) and the amount of load-varying or demand-related costs that would be recovered through the proposed without-RDM residential connection charge ($1.50 per bill).

[40] Petitioner's Exhibit 7-H (MTD), Schedule 1.

[41] The 0.16¢/kWh result is derived by dividing $13.5 million by residential sales of 8.7 million megawatt-hours.

about $28 per year.[42] Thus, under my proposal, the 1,500 kWh customer would contribute three times more than the 500 kWh customer, in direct proportion to their usage and consistent with accepted principles of cost-causation.

In contrast, under the Company's proposal to recover $13.5 million of load-varying and demand-related costs through the fixed connection charge, each residential customer would contribute $18 per year toward recovery of such costs regardless of that customer's usage. A below-average 500 kWh customer would therefore pay almost double their fair share of these load-varying and demand-related costs under the Company's proposal while an above-average 1,500 kWh customer would pay less than two-thirds of their fair share.

D. DEI's Proposal for the Residential Connection Charge Would Dampen Energy Price Signals

Q: Would the Company's proposal to increase the residential connection charge send appropriate price signals?

A: No. As discussed above, DEI proposes to set the without-RDM residential connection charge at a rate that greatly exceeds the cost to connect a residential customer. The amount in excess of the customer connection cost represents usage-related costs that are more appropriately recovered in the volumetric energy rate. However, under the Company's proposal, this excess over the customer connection cost would instead be inappropriately recovered through the fixed connection charge. This shift in the recovery of usage-related costs from the volumetric energy rate to the fixed connection charge would dampen

[42] Based on data provided in Schedule 1 of Petitioner's Exhibit 7-H (MTD), I estimate monthly usage of about 960 kWh for an average residential customer.

price signals and discourage economically efficient behavior by residential customers.

Q: To what extent would the Company's proposal to increase the residential fixed connection charge dampen price signals provided by the residential volumetric energy rate?

A: With a fixed amount of revenue requirements to be recovered from the residential class, the higher the residential fixed connection charge, the lower the volumetric energy rate, and vice versa. With the residential fixed connection charge set at $10.54 in the without-RDM proposal, DEI proposes an average volumetric energy rate (average across the three proposed energy blocks) of 12.51¢/kWh in order to recover the proposed allocation of test year revenue requirements to residential customers.[43] If, instead, the fixed connection charge were set at the cost-based rate of $9.04, I estimate that the average volumetric energy rate would have to be increased to 12.67¢/kWh to recover the same allocated revenue requirement.

In other words, DEI is proposing an average residential energy rate for the without-RDM scenario that is 0.16¢/kWh, or about 1.2%, less than what the volumetric rate would be if the residential fixed connection charge were set at the cost-based rate of $9.04. Thus, the Company's proposal for the without-RDM residential connection charge would dampen the price signal provided by the volumetric energy rate by about 1.2%.[44]

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[43] Calculated based on data provided in '1-5-16(a)(2) Workpaper 2_RS Rate Design Summary.XLSM'.

[44] To be precise, the Company's proposal for the residential connection charge would dampen price signals by about 1.2% if DEI were proposing a flat energy rate. As discussed in Section IV below, the Company's proposal to maintain a declining-block rate structure would even further dampen price signals.

Q: How would residential customers likely respond to the reduction in the energy price signal resulting from the Company's proposal for the residential connection charge?

A: Since the volumetric energy rate under the Company's proposals for the residential connection charge would be lower than the volumetric energy rate with a cost-based fixed connection charge of $9.04, we would expect residential customers to consume more energy with the Company's proposed connection charges than they would with a cost-based connection charge. The magnitude of the increase in energy consumption would depend on: (1) the extent to which the volumetric energy rate with the Company's proposed residential connection charge is lower than the volumetric energy rate with a cost-based connection charge; and (2) the price elasticity of electricity demand.

Q: What is the price elasticity of electricity demand?

A: Residential customers respond to the price incentives created by the electrical rate structure. Those responses are generally measured as price elasticities, i.e., the ratio of the percentage change in consumption to the percentage change in price. Price elasticities are generally low in the short term and rise over several years, because customers have more options for increasing or reducing energy usage in the medium to long term. For example, a review by Espey and Espey (2004) of 36 articles on residential electricity demand published between 1971 and 2000 reports short-run elasticity estimates of about −0.35 on average across studies and long-run elasticity estimates of about −0.85 on average across studies.[45] In other words, on average across these studies, consumption

[45] The citation for this study is provided in Attachment JFW-11.

decreased by 0.35% in the short term and by 0.85% in the long term for every 1% increase in price.

Studies of electric price response typically examine the change in usage as a function of changes in the marginal rate paid by the customer.[46] Table 2 below lists the results of seven studies of marginal-price elasticity over the last forty years.[47]

Table 2: Summary of Marginal-Price Elasticities

Authors	Date	Elasticity Estimates
Acton, Bridger, and Mowill	1976	−0.35 to −0.7
McFadden, Puig, and Kirshner	1977	−0.25 without electric space heat and −0.52 with space heat
Barnes, Gillingham, and Hageman	1981	−0.55
Henson	1984	–0.27 to –0.30
Reiss and White	2005	−0.39
Xcel Energy Colorado	2012	–0.3 (at years 2 and 3)
Orans et al, on BC Hydro inclining-block rate	2014	–0.13 in 3rd year of phased-in rate

Q: What would be a reasonable estimate of the marginal-price elasticity for changes in the residential volumetric energy rate?

A: From Table 2, it appears that –0.3 would be a reasonable mid-range estimate of the impact over a few years.

Q: What would be a reasonable estimate of the effect on energy use from the Company's proposal for the residential fixed connection charge for the without-RDM scenario?

[46] For residential customers, that would be the energy rate.

[47] The citations for these studies are provided in Attachment JFW-11.

A: As discussed above, if the residential connection charge were increased as proposed by DEI for the without-RDM scenario, the volumetric energy rate would be about 1.2% less than what the volumetric energy rate would be if the residential connection charge were set at the cost-based rate of $9.04. Assuming an elasticity of –0.3, this 1.2% reduction in the volumetric energy rate would result in an increase in energy consumption of about 0.4% for the average residential customer. This means that all else equal, residential load after a few years with a residential connection charge as proposed by DEI under the without-RDM scenario would be expected to be about 0.4% higher than it would have been if the residential connection charge had been set at the cost-based rate of $9.04.

IV. Residential Energy Rates

Q: Please describe the current structure of the Company's volumetric energy rates for residential customers.

A: The Company's residential energy rates currently employ a "declining-block" rate structure. Under a declining-block rate structure, a customer pays a higher volumetric rate for usage up to a certain threshold amount (i.e., a "block" of usage) than for usage that exceeds that threshold. The Company's current residential energy rate uses three energy blocks: (1) for monthly usage up to 300 kWh; (2) for monthly usage between 301 and 1,000 kWh; and (3) for monthly usage in excess of 1,000 kWh. Residential customers currently pay a rate of: (1) 8.91¢/kWh for monthly usage up to 300 kWh; (2) 5.19¢/kWh (a 42% discount from the first-block rate) for monthly usage in excess of 300kWh but up to 1,000 kWh; and (3) 4.26¢/kWh (an 18% discount from the second-block rate and a 48% discount from the first-block rate) for monthly usage in excess of 1,000 kWh.[48]

Q: Please describe the Company's proposal with regard to the design of volumetric energy rates for residential customers.

A: The Company proposes two different declining-block rate structures for residential energy rates depending on whether the Commission approves the proposed Revenue Decoupling Mechanism ("RDM"). In both cases, DEI proposes to continue employing three energy blocks. For the without-RDM block energy rates, DEI proposes to reduce the discounts between the first and second block rates and between the second and third block rates compared to the current block rate discounts. For the with-RDM block energy rates, the Company proposes to narrow the spread between block rates even further.

Q: Have you completed your analysis of the Company's proposal for the design of residential energy rates?

A: No. I have not been able to complete my analysis of the Company's proposals for residential energy rates at this time due to extensive delays caused by inconsistencies in the Company's rate design workpapers and by the Company's failure to-date to fully document its derivation of the proposed energy rates. However, my preliminary analysis indicates that DEI lacks a reasonable basis for continuing to employ a declining-block rate structure for residential energy rates. The declining-block rate structures proposed by DEI in either the with-RDM or without-RDM scenarios would recover demand-related costs at a higher rate in the first energy block than in the second and

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[48] For residential customers taking service under Contract Rider No. 6.3 (Optional High Efficiency Residential Service), the third-block rate of 4.26¢/kWh applies solely in the months July through October. For all other months, the third-block rate is 3.62¢/kWh.

third blocks, and thereby would further dampen energy price signals and promote inefficient customer behavior.

I will address the Company's proposal regarding residential energy rates in supplemental testimony.

V. Revenue Decoupling Mechanism

Q: Have you completed your analysis of the Company's proposal to implement a Revenue Decoupling Mechanism?

A: No. I have not been able to complete my analysis of the Company's proposal for a Revenue Decoupling Mechanism at this time due to outstanding issues regarding the Company's forecast of residential billing determinants for the 2020 test year.[49] However, my preliminary analysis indicates that the proposed RDM would not provide any tangible economic benefits to residential customers. To the contrary, over the proposed five-year RDM implementation period, residential customers would be expected to pay more for electric service with than without the RDM. In other words, the proposed RDM would be expected to not only ensure, but also enhance revenue recovery for DEI and its shareholders between rate cases.

I will address the Company's RDM proposal in detail in supplemental testimony once the outstanding issues regarding the Company's forecast of residential billing determinants for the 2020 test year are resolved.

[49] *See* CAC Data Request Sets 19 and 20 (Attachment JFW-3).

VI. Conclusions and Recommendations

Q: What do you conclude with regard to DEI's proposal for allocating the 2020 test-year revenue deficiency?

A: The Commission should reject the Company's proposal for allocating the requested revenue deficiency because it relies on the results of a class cost-of-service study that does not allocate production and distribution plant costs in a manner that reasonably reflects each class's responsibility for such costs. Correcting for this misallocation yields dramatically different results for the residential class. Specifically, the Company's COSS indicates that residential base revenues would have to be increased by about $283.7 million, or about 28.7%, to achieve the requested rate of return. In contrast, the corrected COSS indicates that residential base revenues would have to be increased by about $179.9 million, or about 18.2%, to achieve the requested rate of return.

Q: What do you conclude with respect to the Company's proposal to increase the residential fixed connection charge?

A: The Company proposes two different connection charges depending on whether the Commission approves the proposed Revenue Decoupling Mechanism ("RDM"). Specifically, in the event that the Commission approves the proposed RDM, DEI proposes to set the residential connection charge at $9.80 per residential bill, which is the Company's estimate of the cost to connect a residential customer. However, if the Commission rejects the RDM proposal, DEI proposes to set the residential connection charge at $10.54 per residential bill.

Regardless of whether the proposed RDM is approved, the Commission should reject both of the Company's proposals for setting the residential connection charge. A $9.80 residential connection charge would recover $0.76, or about 8%, more than the actual cost to connect a residential customer. In other words, the Company's estimate of residential connection cost overstates the actual cost to serve by about 8%.

On the other hand, by the Company's own admission, a $10.54 residential connection charge would exceed the Company's (overstated) estimate of the cost to serve. Consequently, the Company's proposal for a $10.54 residential connection charge runs contrary to long-standing principles for designing cost-based rates since it would inappropriately shift recovery of load-related costs from the volumetric energy rate to the fixed connection charge. The Company's proposal to recover load-related costs through the residential connection charge would dampen price signals to consumers for reducing energy usage, disproportionately and inequitably increase bills for the Company's smallest residential customers, and result in subsidization of larger residential customers' costs by customers with below-average usage.

Consequently, the Commission should reject both of the Company's proposals for the residential connection charge. Instead, I recommend that the residential connection charge be maintained at the current rate of $9.01 per residential bill, reflecting the actual cost to connect a residential customer. Consistent with long-standing cost-causation and rate-design principles, a monthly connection charge of $9.01 would provide for the recovery of the cost of meters, service drops, and customer services required to connect a residential customer.

Q: What do you conclude with respect to DEI's proposal to implement a declining-block structure for residential volumetric energy rates?

A: I have not been able to complete my analysis of the Company's proposals for residential energy rates at this time due to extensive delays caused by inconsistencies in the Company's rate design workpapers and by the Company's failure to-date to fully document its derivation of the proposed energy rates. However, my preliminary analysis indicates that DEI lacks a reasonable basis for continuing to employ a declining-block rate structure for residential energy rates. The declining-block rate structures proposed by DEI in either the with-RDM or without-RDM scenarios would recover demand-related costs at a higher rate in the first energy block than in the second and third blocks, and thereby would further dampen energy price signals and promote inefficient customer behavior.

I will address the Company's proposal regarding residential energy rates in supplemental testimony.

Q: What do you conclude with regard to the Company's proposal to implement a Revenue Decoupling Mechanism?

A: I have not been able to complete my analysis of the Company's proposal for a Revenue Decoupling Mechanism at this time due to outstanding issues regarding the Company's forecast of residential billing determinants for the 2020 test year. However, my preliminary analysis indicates that the proposed RDM would not provide any tangible economic benefits to residential customers. To the contrary, over the proposed five-year RDM implementation period, residential customers would be expected to pay more for electric service with than without the RDM. In other words, the proposed RDM would be expected to not only ensure, but also enhance revenue recovery for DEI and its shareholders between rate cases.

I will address the Company's RDM proposal in detail in supplemental testimony once the outstanding issues regarding the Company's forecast of residential billing determinants for the 2020 test year are resolved.

Q: Does this conclude your direct testimony?

A: Yes, at this time. However, I expressly reserve the right to supplement, revise, and correct my testimony at a later date.

VERIFICATION

I, Jonathan Wallach, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Jonathan Wallach

October 30, 2019
Date

ATTACHMENT JFW-1

Qualifications of

JONATHAN F. WALLACH

Resource Insight, Inc.
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SUMMARY OF PROFESSIONAL EXPERIENCE

1990–Present **Vice President, Resource Insight, Inc.** Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, regulation, and restructuring. Designs and assesses resource-planning strategies for regulated and competitive markets, including estimation of market prices and utility-plant stranded investment; negotiates restructuring strategies and implementation plans; assists in procurement of retail power supply.

1989–90 **Senior Analyst, Komanoff Energy Associates.** Conducted comprehensive cost-benefit assessments of electric-utility power-supply and demand-side conservation resources, economic and financial analyses of independent power facilities, and analyses of utility-system excess capacity and reliability. Provided expert testimony on statistical analysis of U.S. nuclear plant operating costs and performance. Co-wrote *The Power Analyst*, software developed under contract to the New York Energy Research and Development Authority for screening the economic and financial performance of non-utility power projects.

1987–88 **Independent Consultant.** Provided consulting services for Komanoff Energy Associates (New York, New York), Schlissel Engineering Associates (Belmont, Massachusetts), and Energy Systems Research Group (Boston, Massachusetts).

1981–86 **Research Associate, Energy Systems Research Group.** Performed analyses of electric utility power supply planning scenarios. Involved in analysis and design of electric and water utility conservation programs. Developed statistical analysis of U.S. nuclear plant operating costs and performance.

EDUCATION

BA, Political Science with honors and Phi Beta Kappa, University of California, Berkeley, 1980.

Massachusetts Institute of Technology, Cambridge, Massachusetts. Physics and Political Science, 1976–1979.

PUBLICATIONS

“The Future of Utility Resource Planning: Delivering Energy Efficiency through Distributed Utilities” (with Paul Chernick), *International Association for Energy Economics Seventeenth Annual North American Conference* (460–469). Cleveland, Ohio: USAEE. 1996.

"The Price is Right: Restructuring Gain from Market Valuation of Utility Generating Assets" (with Paul Chernick), *International Association for Energy Economics Seventeenth Annual North American Conference* (345–352). Cleveland, Ohio: USAEE. 1996.

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distribution Utilities" (with Paul Chernick), *1996 Summer Study on Energy Efficiency in Buildings* 7(7.47–7.55). Washington: American Council for an Energy-Efficient Economy, 1996.

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"Risk Analysis of Procurement Strategies for Residential Standard Offer Service" (with Paul Chernick, David White, and Rick Hornby) report to Maryland Office of People's Counsel. 2008. Baltimore: Maryland Office of People's Counsel.

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Cost allocation and rate design; rate-stabilization mechanism.

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Cost allocation and rate design.

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Cost allocation and rate design.

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Allocation of Smart Grid costs. Recovery of conduit fees. Rate design.

Nova Scotia UARB Case No. NSUARB P-887(16), Nova Scotia Power 2017-2019 Fuel Stability Plan; Nova Scotia Consumer Advocate. Direct, May 2016; Reply, June 2016.

Base Cost of Fuel forecast. Allocation of Maritime Link capital costs. Fuel cost hedging plan.

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Cost basis for residential customer charges.

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Sanctions for imprudent fuel-contracting practices.

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Kentucky PSC Case No. 2016-00371, Louisville Gas & Electric Company electric rates; Sierra Club. Direct, March 2017.

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Cost Allocation. Cost basis for residential customer charges. Demand charges for net metering customers.

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Cost basis for residential customer charges. Design of residential energy rates.

PUC of Texas Docket No. 48401, Texas-New Mexico Power Company electric rates; Office of Public Utility Counsel. Direct, Cross-Rebuttal, August 2018.

Cost of service study. Allocation of requested revenue increase.

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Indiana Utility Regulatory Commission Cause No. 45159, Northern Indiana Public Service Company electric rates; Citizens Action Coalition of Indiana. Direct, February 2019; Responsive, June 2019.

Proposed industrial rate restructuring. Allocation of requested revenue increase. Cost basis for residential customer charges.

Indiana Utility Regulatory Commission Cause No. 45235, Indiana Michigan Power Company electric rates; Citizens Action Coalition of Indiana and Indiana Community Action Association. Direct, August 2019; Cross-Answering, September 2019.

Proposed investment in advanced metering infrastructure. Allocation of requested revenue increase. Cost basis for residential customer charges. Design of residential energy rates. Proposed residential demand rate pilot.

ATTACHMENT JFW-2

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	)	**CAUSE NO. 45253**

VERIFIED STATEMENT OF JONATHAN WALLACH

1. My name is Jonathan F. Wallach. I am Vice President of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

2. I have worked as a consultant to the electric power industry since 1981. From 1981 to 1986, I was a Research Associate at Energy Systems Research Group. In 1987 and 1988, I was an independent consultant. From 1989 to 1990, I was a Senior Analyst at Komanoff Energy Associates. I have been in my current position at Resource Insight since 1990.

3. Over the past four decades, I have advised and testified on behalf of clients on a wide range of economic, planning, and policy issues relating to the regulation of electric utilities, including: electric-utility restructuring; wholesale-power market design and operations; transmission pricing and policy; market-price forecasting; market valuation of generating assets and purchase contracts; power-procurement strategies; risk assessment and mitigation; integrated resource planning; mergers and acquisitions; cost allocation and rate design; and energy-efficiency program design and planning.

4. I have sponsored expert testimony in more than 90 state, provincial, and federal proceedings in the U.S. and Canada, including before the Indiana Utility Regulatory Commission ("the Commission") in Cause Nos. 44967, 45029, 45159, and 45235.

5. I have testified in more than 30 general rate cases across the nation, including in Duke Energy's most recent general rate cases in North and South Carolina.

6. I have reviewed Duke Energy Indiana's ("Duke" or the "Company") pre-filed testimony in Cause No. 45253 and have reviewed the primary results of Citizens Action Coalition's ("CAC") discovery on the Company in Cause No. 45253 to date. I have participated in several phone calls with the Company throughout September and October, attempting to find critical information for my case-in-chief filing that has been extremely burdensome and time-consuming for my team at Resource Insight and me to find ourselves.

7. During my review of Duke's case-in-chief testimony, workpapers, MSFRs, and exhibits in late-August of 2019, I discovered that the presented Cost of Service Study ("COSS") workpaper did not actually functionalize, classify, and allocate test-year costs. In other words, Confidential Workpaper 2-MTD, sheet RC ALOCC, does not have any formulas or other critical pieces of information, just 69,000+ rows of output data from the Company's proprietary COSS software model pasted in. I notified CAC's counsel so she could request Duke to provide a copy of the COSS that would allow me to review the necessary information to perform my analysis for my case-in-chief submission.

8. On September 19, 2019, I attended a call with various Duke representatives and other consumer parties interested in the COSS to discuss how parties were having difficulty finding critical information that should be located in the MSFRs, workpapers, and exhibits and how best to rectify the situation. Duke provided a preview of their proprietary model via Skype and received multiple questions from expert witnesses as it became clear that this presentation did not show how this new model performed the functionalization, classification, and allocation of costs as a traditional spreadsheet-based COSS model would. It also became clear that Duke had not provided a clear statement or chain of evidence in terms of which information was being fed into the model or calculated within the model and provided as an output somewhere in the Company's MSFRs or workpapers. Experts asked several questions with regard to how this new model actually worked and where experts could figure out whether critical information was fed into, represented in, and/or coming out of the model. Experts also asked several questions with regard to where they could find certain information and supporting information that had been difficult to locate on their own. For example, experts asked questions and voiced concerns about how the load data is fed into or calculated in the model, how external allocators were developed, and where to find the loss factors. I found it concerning that the Duke representatives themselves were struggling with where to find certain information. They also admitted that certain information, like detailed O&M expenses by FERC account, were rolled up into summarized information as an output from Duke's proprietary COSS software model and had not been provided at the detailed level in their case-in-chief submission. They further confirmed our concerns that their chain of evidence was broken between various spreadsheets at issue in this case, meaning that with the information provided, when Duke reaches a result in one spreadsheet, it merely copies those numbers and pastes them into the next spreadsheet, not linking the spreadsheets in any way or even leaving a citation trail so that parties could reasonably find where the next logical chain of evidence would be. In my experience, Commissions have required and utilities have presented information with a clear and transparent chain of information with spreadsheets linked between each other.

On the call, Duke agreed to put forth some spreadsheets with formulae intact for experts and counsel to review and discuss with Duke the following week.

9. On September 23, 2019, Duke provided an Excel-based replica of the COSS software model via email broken into two separate Excel workbooks (Class and Functional Allocation workbooks).

10. On September 25, 2019, I participated in another phone/Skype call with Duke and various other consumer representatives interested in the COSS issues. On this call, certain parties pointed out several deficiencies in these two Excel workbooks, and Duke agreed to attempt to correct those and supplement it with a new version of the Excel based replica of the COSS model. One major deficiency CAC asked Duke to address was the fact that the allocation factors had been copied as values from various undocumented MSFRs and workpapers, making it impossible for the parties to follow the chain of evidence regarding the derivation of those allocation factors. Duke later provided a key attempting to address this deficiency, which has been helpful, but has not come close to addressing the problem. Another concern voiced on this call was whether Duke would agree to make specifically requested changes to the COSS model for parties for purposes of their analysis—a standard discovery function in my experience and an elevated concern here considering Duke's reliance on a new model. Duke also admitted on this call that they had created an earlier version of this Excel-based replica of the COSS model to verify the proprietary model results, yet they just made it available to parties on September 23, 2019.

11. On September 30, 2019, Duke provided parties with a second version of the Excel-based replica of the COSS model via email. In this new version, Duke combined the Class and Functional Allocation files into one file, simplified the mapping from the Function Allocation sheets to the COSS, added an Adjustment column to the Function Allocation sheets, grouped the Input sheets into one section, added Net Operating Income and Rate Increase workpapers COSS16-26, added an "Impact of Changes" sheet to compare the results from any changes made in this file to amounts filed in the rate case, and added a second level reference to the allocation factor input sheets.

12. Throughout the week of September 30, 2019, I worked to gather a more comprehensive list of deficiencies and outstanding issues to again bring to Duke along with a proposal for a request for extension to the current procedural schedule. It is my understanding that Duke rejected our request to refile the MSFRs, workpapers, and exhibits so as to improve the documentation, cross-referencing, and linkage between these spreadsheets, which has and will continue to significantly impair my ability to complete my analysis at all, but especially for an October 30, 2019 due date. It is also my understanding that Duke rejected our request for a three-week extension, despite our stated concern that we spent over a month working to try and figure out the COSS issue.

13. In my experience, I have never seen a rate filing that compares to this in terms of the unsupported, inadequate, unorganized, and undocumented presentation of evidence. I can attest to the fact that these issues did not exist in the most recent Duke Energy Carolinas rate case, Docket No. 2018-319-E before the South Carolina Public Utilities Commission.

14. I affirm, under the penalties of perjury, that the foregoing statements are based on personal knowledge and are true and correct to the best of my knowledge, information and belief.

ATTACHMENT JFW-3

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARNGES FOR ELECTRIC UTILITY SERVICE THORUGH A STEP-IN OF NEW RATES AND CHARNGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	)	**CAUSE NO. 45253**

CITIZEN ACTION COALITION'S NINETEENTH DATA REQUESTS TO DUKE ENERGY INDIANA

Citizens Action Coalition of Indiana, Inc. ("CAC"), by and through its legal counsel, hereby submit this Nineteenth Set of Data Requests to Duke Energy Indiana, LLC. ("DEI"). Please forward responses to the data requests below to the undersigned counsel.

GENERAL INSTRUCTIONS

1) **Definitions:** For the purposes of these data requests, the following definitions shall apply:

   a) The term "DEI" means and includes Duke Energy Indiana, LLC, its parent company or companies (e.g., Duke Energy, LLC) and any and all affiliates and/or subsidiaries, successors, predecessors and agents, including Duke Energy Indiana, Inc., Cinergy, Inc., PSI Energy, Inc., and any and all of their affiliates, subsidiaries or predecessors.

   b) The term "Company" means and includes Duke Energy Indiana, LLC, its parent company or companies (e.g., Duke Energy, LLC) and any and all affiliates and/or subsidiaries, successors, predecessors and agents, including Cinergy, Inc., PSI Energy, Inc., and any and all of their affiliates, subsidiaries or predecessors.

c) “Document” means all written, recorded or graphic matters, however produced or reproduced, pertaining in any manner to the subject of this proceeding, whether or not now in existence, without limiting the generality of the foregoing, all originals, copies and drafts of all writings, correspondence, telegrams, notes or sound recordings of any type of personal or telephone communication, or of meetings or conferences, minutes of directors or committee meetings, memoranda, inter-office communications, studies, analyses, reports, results of investigations, reviews, contracts, agreements, working papers, statistical records, ledgers, books of account, vouchers, bank checks, x-ray prints, photographs, films, videotapes, invoices, receipts, computer printouts or other products of computers, computer files, stenographer’s notebooks, desk calendars, appointment books, diaries, or other papers or objects similar to any of the foregoing, however denominated. If a document has been prepared in several copies, or additional copies have been made, and the copies are not identical (or which, by reasons of subsequent modification of a copy by the addition of notations, or other modifications, are no longer identical) each non-identical copy is a separate “document.”

d) “And” or “or” shall be construed conjunctively or disjunctively as necessary to make the requests inclusive rather than exclusive.

e) The term “you” and “your” refer to “DEI.”

f) The term “person” means any natural person, corporation, corporate division, partnership, limited liability company, other unincorporated association, trust, government agency, or entity.

g) The term “regarding” means consisting of, containing, mentioning, suggesting, reflecting, concerning, regarding, summarizing, analyzing, discussing, involving, dealing with, emanating from, directed at, pertaining to in any way, or in any way logically or factually connected or associated with the matter discussed.

h) The singular as used herein shall include the plural and the masculine gender shall include the feminine and the neuter.

i) “Identify” or “identifying” or “identification” when used in reference to a person that is a natural person means to state: the full name of the person and any names under which he conducts business; the current employer of the person, the person’s job title and classification, the present or last known work address of the person; and, the present or last known telephone number of the person.

j) “Identify” or “identifying” or “identification” when used in reference to a person other than a natural person means to state: the full name of the person and any names under which it conducts business; the present or last known address of the person; and, the present or last known telephone number of the person.

k) "Identify" or "identifying" or "identification" when used in reference to a document means to provide with respect to each document requested to be identified by these discovery requests a description of the document that is sufficient for purposes of a request to produce or a subpoena duces tecum, including the following:

(a) the type of document (e.g., letter, memorandum, etc.);

(b) the date of the document;

(c) the title or label of the document;

(d) the Bates stamp number or other identifier used to number the document for use in litigation;

(e) the identity of the originator;

(f) the identity of each person to whom it was sent;

(g) the identity of each person to whom a copy or copies were sent;

(h) a summary of the contents of the document;

(i) the name and last known address of each person who presently has possession, custody or control of the document; and,

(j) if any such document was, but is no longer, in your possession, custody or control or is no longer in existence, state whether it: (1) is missing or lost; (2) has been destroyed; or (3) has been transferred voluntarily or involuntarily, and if so, state the circumstances surrounding the authorization for each such disposition and the date of such disposition.

l) "Identify" or "identifying" or "identification" when used in reference to communications means to state the date of the communication, whether the communication was written or oral, the identity of all parties and witnesses to the communication, the substance of what was said and/or transpired and, if written, identify the document(s) containing or referring to the communication.

m) "Current" when used in reference to time means in the present time of this data request.

n) "Customer" means a person who buys retail electricity on a regular and ongoing basis.

o) "Workpapers" are defined as original, electronic, machine-readable, unlocked, Excel format (where possible) with formulas intact.

2) **OTHER INSTRUCTIONS**

a) Responses are to be provided in electronic format (e.g., text documents should be in the original word processor file format or PDF, data files should be in Excel).

b) If you contend that any response to any data request may be withheld under the attorney-client privilege, the attorney work product doctrine or any other privilege or basis, please state the following with respect to each such response in order to explain the basis for the claim of privilege and to permit adjudication of the propriety of that claim:

   (a) The privilege asserted and its basis;

   (b) The nature of the information withheld; and,

   (c) The subject matter of the document, except to the extent that you claim it is privileged.

c) For any document or set of documents DEI objects to providing to CAC on the grounds it is burdensome or voluminous, please identify the specific document (see instruction 1(k) above).

d) These data requests are to be answered with reference to all information in your possession, custody or control or reasonably available to you. These data requests are intended to include requests for information, which is physically within your possession, custody or control as well as in the possession, custody or control of your agents, attorneys, or other third parties from which such documents may be obtained.

e) If any data request cannot be responded to or answered in full, answer to the extent possible and specify the reasons for your inability to answer fully.

f) These data requests are continuing in nature and require supplemental responses should information unknown to you at the time you serve your responses to these data requests subsequently become known.

g) For each response, identify all persons (see instruction 1(j)) that were involved in the preparation of the answers to the interrogatories below and/or are responsible for compiling and providing the information contained in each answer.

h) Identify which witness(es) at the hearing(s) is competent to adopt and/or discuss the response.

i) Please produce the requested documents in electronic format to the following individuals:

Jennifer A. Washburn
Margo Tucker
Citizens Action Coalition of Indiana, Inc.
1915 W. 18th Street, Suite C
Indianapolis, Indiana 46202
jwashburn@citact.org
mtucker@citact.org

j) Wherever the response to an interrogatory or request consists of a statement that the requested information is already available to CAC, provide a detailed citation to the document that contains the information. This citation shall include the title of the document, relevant page number(s), and to the extent possible paragraph number(s) and/or chart/table/figure number(s).

k) In the event that any document referred to in response to any request for information has been destroyed, specify the date and the manner of such destruction, the reason for such destruction, the person authorizing the destruction and the custodian of the document at the time of its destruction.

l) CAC reserves the right to serve supplemental, revised, or additional discovery requests as permitted in this proceeding.

3) Glossary of Acronyms Used in Data Requests
"CCR" means Coal Combustion Residuals
"CO_2" means carbon dioxide
"DOE" means United States Department of Energy
"EPRI" means Electric Power Research Institute
"IGCC" means Integrated Gasification Combined Cycle
"IRP" means Integrated Resource Plan
"NETL" means National Energy Technology Laboratory
"R&D" means research and development
"U.S. EPA" means United States Environmental Protection Agency

Respectfully submitted,

Jennifer A. Washburn

Jennifer A. Washburn, Atty. No. 30462-49
Citizens Action Coalition of Indiana, Inc.
1915 W. 18th Street, Suite C
Indianapolis, Indiana 46202
jwashburn@citact.org
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(Specific requests begin on next page)

Cause No. 45253
October 24, 2019
CAC Set 19 to Duke

DATA REQUESTS

19.1 Please Reference DEI response to CAC Data Request 12-15(b), 'Attachment CAC 12.15-B (Bate No. 090013918-056294).xlsx'.

a) The referenced spreadsheet indicates that the Company forecasts an average number of monthly RS customers in 2020 of 736,308. Please explain why this figure differs from the 752,130 amount reported in Schedule 1 of Petitioner's Exhibit 7-H (MTD) for the 2020 test year.

b) The referenced spreadsheet indicates that the Company forecasts annual RS sales in 2020 of 9,051,878 MWh. Please explain why this figure differs from the 8,666,906 MWh amount reported in Schedule 1 of Petitioner's Exhibit 7-H (MTD) for the 2020 test year.

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARNGES FOR ELECTRIC UTILITY SERVICE THORUGH A STEP-IN OF NEW RATES AND CHARNGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	)	**CAUSE NO. 45253**

CITIZEN ACTION COALITION'S TWENTIETH DATA REQUESTS TO DUKE ENERGY INDIANA

Citizens Action Coalition of Indiana, Inc. ("CAC"), by and through its legal counsel, hereby submit this Twentieth Set of Data Requests to Duke Energy Indiana, LLC. ("DEI"). Please forward responses to the data requests below to the undersigned counsel.

GENERAL INSTRUCTIONS

1) **Definitions:** For the purposes of these data requests, the following definitions shall apply:

a) The term "DEI" means and includes Duke Energy Indiana, LLC, its parent company or companies (e.g., Duke Energy, LLC) and any and all affiliates and/or subsidiaries, successors, predecessors and agents, including Duke Energy Indiana, Inc., Cinergy, Inc., PSI Energy, Inc., and any and all of their affiliates, subsidiaries or predecessors.

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c) "Document" means all written, recorded or graphic matters, however produced or reproduced, pertaining in any manner to the subject of this proceeding, whether or not now in existence, without limiting the generality of the foregoing, all originals, copies and drafts of all writings, correspondence, telegrams, notes or sound recordings of any type of personal or telephone communication, or of meetings or conferences, minutes of directors or committee meetings, memoranda, inter-office communications, studies, analyses, reports, results of investigations, reviews, contracts, agreements, working papers, statistical records, ledgers, books of account, vouchers, bank checks, x-ray prints, photographs, films, videotapes, invoices, receipts, computer printouts or other products of computers, computer files, stenographer's notebooks, desk calendars, appointment books, diaries, or other papers or objects similar to any of the foregoing, however denominated. If a document has been prepared in several copies, or additional copies have been made, and the copies are not identical (or which, by reasons of subsequent modification of a copy by the addition of notations, or other modifications, are no longer identical) each non-identical copy is a separate "document."

d) "And" or "or" shall be construed conjunctively or disjunctively as necessary to make the requests inclusive rather than exclusive.

e) The term "you" and "your" refer to "DEI."

f) The term "person" means any natural person, corporation, corporate division, partnership, limited liability company, other unincorporated association, trust, government agency, or entity.

g) The term "regarding" means consisting of, containing, mentioning, suggesting, reflecting, concerning, regarding, summarizing, analyzing, discussing, involving, dealing with, emanating from, directed at, pertaining to in any way, or in any way logically or factually connected or associated with the matter discussed.

h) The singular as used herein shall include the plural and the masculine gender shall include the feminine and the neuter.

i) "Identify" or "identifying" or "identification" when used in reference to a person that is a natural person means to state: the full name of the person and any names under which he conducts business; the current employer of the person, the person's job title and classification, the present or last known work address of the person; and, the present or last known telephone number of the person.

j) "Identify" or "identifying" or "identification" when used in reference to a person other than a natural person means to state: the full name of the person and any names under which it conducts business; the present or last known address of the person; and, the present or last known telephone number of the person.

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(a) the type of document (e.g., letter, memorandum, etc.);

(b) the date of the document;

(c) the title or label of the document;

(d) the Bates stamp number or other identifier used to number the document for use in litigation;

(e) the identity of the originator;

(f) the identity of each person to whom it was sent;

(g) the identity of each person to whom a copy or copies were sent;

(h) a summary of the contents of the document;

(i) the name and last known address of each person who presently has possession, custody or control of the document; and,

(j) if any such document was, but is no longer, in your possession, custody or control or is no longer in existence, state whether it: (1) is missing or lost; (2) has been destroyed; or (3) has been transferred voluntarily or involuntarily, and if so, state the circumstances surrounding the authorization for each such disposition and the date of such disposition.

l) “Identify” or “identifying” or “identification” when used in reference to communications means to state the date of the communication, whether the communication was written or oral, the identity of all parties and witnesses to the communication, the substance of what was said and/or transpired and, if written, identify the document(s) containing or referring to the communication.

m) “Current” when used in reference to time means in the present time of this data request.

n) “Customer” means a person who buys retail electricity on a regular and ongoing basis.

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b) If you contend that any response to any data request may be withheld under the attorney-client privilege, the attorney work product doctrine or any other privilege or basis, please state the following with respect to each such response in order to explain the basis for the claim of privilege and to permit adjudication of the propriety of that claim:

   (a) The privilege asserted and its basis;

   (b) The nature of the information withheld; and,

   (c) The subject matter of the document, except to the extent that you claim it is privileged.

c) For any document or set of documents DEI objects to providing to CAC on the grounds it is burdensome or voluminous, please identify the specific document (see instruction 1(k) above).

d) These data requests are to be answered with reference to all information in your possession, custody or control or reasonably available to you. These data requests are intended to include requests for information, which is physically within your possession, custody or control as well as in the possession, custody or control of your agents, attorneys, or other third parties from which such documents may be obtained.

e) If any data request cannot be responded to or answered in full, answer to the extent possible and specify the reasons for your inability to answer fully.

f) These data requests are continuing in nature and require supplemental responses should information unknown to you at the time you serve your responses to these data requests subsequently become known.

g) For each response, identify all persons (see instruction 1(j)) that were involved in the preparation of the answers to the interrogatories below and/or are responsible for compiling and providing the information contained in each answer.

h) Identify which witness(es) at the hearing(s) is competent to adopt and/or discuss the response.

i) Please produce the requested documents in electronic format to the following individuals:

Jennifer A. Washburn
Margo Tucker
Citizens Action Coalition of Indiana, Inc.
1915 W. 18th Street, Suite C
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jwashburn@citact.org
mtucker@citact.org

j) Wherever the response to an interrogatory or request consists of a statement that the requested information is already available to CAC, provide a detailed citation to the document that contains the information. This citation shall include the title of the document, relevant page number(s), and to the extent possible paragraph number(s) and/or chart/table/figure number(s).

k) In the event that any document referred to in response to any request for information has been destroyed, specify the date and the manner of such destruction, the reason for such destruction, the person authorizing the destruction and the custodian of the document at the time of its destruction.

l) CAC reserves the right to serve supplemental, revised, or additional discovery requests as permitted in this proceeding.

3) Glossary of Acronyms Used in Data Requests

"CCR" means Coal Combustion Residuals
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"EPRI" means Electric Power Research Institute
"IGCC" means Integrated Gasification Combined Cycle
"IRP" means Integrated Resource Plan
"NETL" means National Energy Technology Laboratory
"R&D" means research and development
"U.S. EPA" means United States Environmental Protection Agency

Respectfully submitted,

Jennifer A. Washburn

Jennifer A. Washburn, Atty. No. 30462-49
Citizens Action Coalition of Indiana, Inc.
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(Specific requests begin on next page)

Cause No. 45253
October 25, 2019
CAC Set 20 to Duke

DATA REQUESTS

20.1 Schedule 1 of Petitioner's Exhibit 7-H (MTD) reports a figure of 752,130 for the average number of monthly RS customers in the 2020 test year. Please explain why this figure differs from the 718,643 amount reported in MSFR Workpaper COSS191-MTD for the number of billed RS customers in the 2020 test year.

ATTACHMENT JFW-4

ELECTRIC UTILITY
COST ALLOCATION MANUAL

January, 1992

NATIONAL ASSOCIATION OF
REGULATORY UTILITY COMMISSIONERS

1101 Vermont Avenue NW
Washington, D.C. 20005
USA
Tel: (202) 898-2200
Fax: (202) 898-2213
www.naruc.org

$25.00

CONTENTS

Exhibit 4-1
(Continued)

CLASSIFICATION OF EXPENSES[1]

Other Power Generation Operation

FERC Uniform System of Account	Description	Demand Related	Energy Related
546, 548-554	All Accounts	x	-
547	Fuel	-	x

Other Power Supply Expenses

FERC Uniform System of Account	Description	Demand Related	Energy Related
555	Purchased Power	x[5]	x[5]
556	System Control & Load Dispatch	x	-
557	Other Expenses	x	-

[1] Direct assignment or "exclusive use" costs are assigned directly to the customer class or group that exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2] In some instances, a portion of hydro rate base may be classified as energy related.

[3] The classification between demand-related and energy-related costs is carried out on the basis of the relative proportions of labor cost contained in the other accounts in the account grouping.

[4] Classified between demand and energy on the basis of labor expenses and material expenses. Labor expenses are considered demand-related, while material expenses are considered energy-related.

[5] As-billed basis.

The cost accounting approach to classification is based on the argument that plant capacity is fixed to meet demand and that the costs of plant capacity should be assigned to customers on the basis of their demands. Since plant output in KWH varies with system energy requirements, the argument continues, variable production costs should be allocated to customers on a KWH basis.

B. Cost Causation

Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability (LOLP), loss of load hours (LOLH), reserve margin, or expected unserved energy (EUE); and (2) that the utility's energy load or load duration curve is a major indicator of the type of plant needed. The type of plant installed determines the cost of the additional capacity. This approach is well represented among the energy weighting methods of cost allocation.

IV. METHODS FOR CLASSIFYING AND ALLOCATING PRODUCTION PLANT COSTS

In the past, utility analysts thought that production plant costs were driven only by system maximum peak demands. The prevailing belief was that utilities built plants exclusively to serve their annual system peaks as though only that single hour was important for planning. Correspondingly, cost of service analysts used a single maximum peak approach to allocate production costs. Over time it became apparent to some that hours other than the peak hour were critical from the system planner's perspective, and utilities moved toward multiple peak allocation methods. The Federal Energy Regulatory Commission began encouraging the use of a method based on the 12 monthly peak demands, and many utilities accordingly adopted this approach for allocating costs within their retail jurisdictions as well as their resale markets.

This section is divided into three parts. The first two contain a discussion of peak demand and energy weighted cost allocation methods. The third part covers time-differentiated cost of service methods for allocating production plant costs. Tables 4-1 through 4-4 contain illustrative load data supplied by the Southern California Edison Company for monthly peak demands, summer and winter peak demands, class noncoincident peak demands, on-peak and off-peak energy use. These data are used to illustrate the derivation of various demand and energy allocation factors throughout this Section as well as Section III.

The common objective of the methods reviewed in the following two parts is to allocate production plant costs to customer classes consistent with the cost impact that the class loads impose on the utility system. If the utility plans its generating capacity additions to serve its demand in the peak hour of the year, then the demand of each class in the peak hour is regarded as an appropriate basis for allocating demand-related production costs.

If the utility bases its generation expansion planning on reliability criteria -- such as loss of load probability or expected unserved energy -- that have significant values in a number of hours, then the classes' demands in hours other than the single peak hour may also provide an appropriate basis for allocating demand-related production costs. Use of multiple-hour methods also greatly reduces the possibility of atypical conditions influencing the load data used in the cost allocation.

TABLE 4-10C

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD

(AVERAGE DEMAND PROPORTION ALLOCATED ON ENERGY)

Rate Class	Energy Allocation Factor - Average MW	Energy Allocatn. Factor (%)	Energy-Related Production Plant Revenue Requirement	Excess Demand Allocation Factor (NCP MW - Avg. MW)	Excess Demand Alloctn. Factor (Percent)	Demand-Related Production Plant Revenue Requirement	Class Production Plant Revenue Requiremnt
DOM	2,440	30.96	190,387,863	2,917	44.05	196,294,822	386,682,685
LSMP	2,669	33.87	208,256,232	2,393	36.14	161,033,085	369,289,317
LP	2,459	31.21	191,870,391	926	13.98	62,313,680	254,184,071
AG&P	254	3.22	19,819,064	318	4.80	21,399,298	41,218,363
SL	58	0.74	4,525,613	68	1.03	4,575,951	9,101,564
TOTAL	7,880	100.00	614,859,163	6,622	100.00	445,616,837	1,060,476,000

Notes: The system load factor is 57.98 percent (7,880 MW/13,591 MW). Thus, 57.98 percent of total production plant revenue requirement is classified as energy-related and allocated to all classes on the basis of their proportions of average system demand. The remaining 42.02 percent is classified as demand-related and allocated to the classes according to their proportions of excess (NCP - average) demand, and allocated to the firm service classes according to their proportions of excess (NCP - average) demand.

Some columns may not add to indicated totals due to rounding.

2. Equivalent Peaker Methods

Objective: Equivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added. They generally result in significant percentages (40 to 75 percent) of total production plant costs being classified as energy-related, with the results that energy unit costs are relatively high and the revenue responsibility of high load factor classes and customers is significantly greater than indicated by pure peak demand responsibility methods.

The premises of this and other peaker methods are: (1) that increases in peak demand require the addition of peaking capacity only; and (2) that utilities incur the costs of more expensive intermediate and baseload units because of the additional energy loads they must serve. Thus, the cost of peaking capacity can properly be regarded as peak demand-related and classified as demand-related in the cost of service study. The difference between the utility's total cost for production plant and the cost of peaking capacity is caused by the energy loads to be served by the utility and is classified as energy-related in the cost of service study.

Data Requirements: This energy weighting method takes a different tack toward production plant cost allocation, relying more heavily on system planning data in addition to load research data. The cost of service analyst must become familiar with system expansion criteria and justify his cost classification on system planning grounds.

A Digression on System Planning with Reference to Plant Cost Allocation:

Generally speaking, electric utilities conduct generation system planning by evaluating the need for additional capacity, then, having determined a need, choosing among the generation options available to it. These include purchases from a neighboring utility, the construction of its own peaking, intermediate or baseload capacity, load management, enhanced plant availability, and repowering among others.

The utility can choose to construct one of a variety of plant-types: combustion turbines (CT), which are the least costly per KW of installed capacity, combined cycle (CC) units costing two to three times as much per KW as the CT, and baseloaded units with a cost of four or more times as much as the CT per KW of installed capacity. The choice of unit depends on the energy load to be served. A peak load of relatively brief duration, for example, less than 1,500 hours per year, may be served most economically by a CT unit. A peak load of intermediate duration, of 1,500 to 4,000 hours per year, may be served most economically by a CC unit. A peak load of long annual duration may be served most economically by a baseload unit.

Classification of Generation:

In the equivalent peaker type of cost study, all costs of actual peakers are classified as demand-related, and other generating units must be analyzed carefully to determine their proportionate classifications between demand and energy. If the plant types are significantly different, then individual analysis and treatment may be necessary. The ideal analysis is a "date of service" analysis. The analyst calculates the installed cost of all units in the dollars of the install date and classifies the peaker cost as demand-related. The remaining costs are classified as energy-related.

ATTACHMENT JFW-5

CAC
IURC Cause No. 45253
Data Request Set No. 12
Received: September 23, 2019

CAC 12.4

Request:

Please reference Diaz Revised Direct, p. 30, ll. 4-19.

a) Please confirm that all production plant costs are classified as demand-related in the retail cost of service study.

b) Please indicate whether secondary pole, conductor, and transformer plant costs are classified in the retail cost of service study as facility-related or connection-related.

c) Please indicate whether secondary pole, conductor, and transformer costs are allocated based on number of customers, diversified class demand, or non-coincident peak demand.

d) For those instances where a secondary transformer serves more than one customer, does the Company size the transformer to serve the expected diversified load on the transformer or the expected sum of the individual customer maximum loads on the transformer? Please explain.

e) Please provide copies of any planning documents or engineering design guidelines which describe Company practice with regard to sizing of secondary transformers.

Response:

a) Yes, all production plant as categorized in the FERC Electric Plant Chart of Accounts in the Uniform System of Accounts is classified as demand related in the retail cost of service study.

b) Secondary pole, secondary conductor, and secondary transformer plant costs are are included in Total Connection Charges. Also included in Total Connection Charges are “fixed connection charges”, “services”, “secondary line transformers”, and “secondary lines”. In Diaz Revised Direct p. 30, lines 16-17, Diaz states that “connection-related charges include electric meters and customer accounts”; in this context, Witness Diaz is referring to the “fixed connection charge” component only. The fixed connection charges, as used by rate design to develop the customer charge, do <u>not</u> include secondary pole, secondary conductor, and secondary transformer plant costs in the customer charge.

c) These costs were allocated to retail customers based on Non-coincident peak demand allocators.

d) We use a diversified load on calculation, built into our Secondary Electrical Design System (SEDS) software, when sizing transformers that serve more than one customer.

e) Transformers serving residential load/customers are sized based on diversified load according to coincidence factors and total numbers of customers per transformer. The diversified load shall not exceed our transformer loading guidelines. However, total connected load can't exceed the cold load pick up guidelines (loss of diversity). Also, flicker needs to be evaluated based on guideline below (not to exceed 4.2%).

Taken from a section of the job aid for SEDS:

Residential Transformer Loading Summary

Maximum Transformer Loading

	Summer	Winter
Carolinas	140%	170%
Midwest	145%	185%

Power Factor - 95%

Locked Rotor Amps

Tonnage	1.5	2	2.5	3	3.5	4	5
	48	63	77	93	112	137	160

Maximum Allowable Flicker – 4.2%

Cold Load (loss of diversity) - Summer – 225%, Winter – 270%

Air Conditioner

Ton	AC	Range/Oven	Misc Load	Total Load (KW)
1.5	1.9	3.0	1.5	6.6
2	2.6	3.0	1.5	7.3
2.5	3.2	3.0	1.5	8.0
3	3.9	3.0	1.5	8.7
3.5	4.5	3.0	1.5	9.4
4	5.2	3.0	2.0	10.6
5	6.5	3.0	2.5	12.5

Heat Pump

Ton	H.P.	Strip	Wtr Htr	Misc Load	Total Load (KW)
1.5	1.9	5	4.5	1.5	13.1
2	2.6	10	4.5	1.5	18.8
2.5	3.2	10	4.5	1.5	19.5
3	3.9	10	4.5	1.5	20.2
3.5	4.5	10	4.5	1.5	20.9
4	5.2	15	4.5	2.0	27.1
5	6.5	15	4.5	2.5	29.0

Assumed load per ton (A/C or Heat Pump) – 1.4KW

Diversity (Coincidence Factor)

Carolinas

Customers	Heat Pump	A/C
1	1	1
2	.695	.82
3	.568	.73
4	.486	.645
5	.427	.58
6	.377	.515
7	.352	.49
8	.337	.475
9	.323	.47
10	.314	.46
11	.314	.46
12 & up	.314	.46

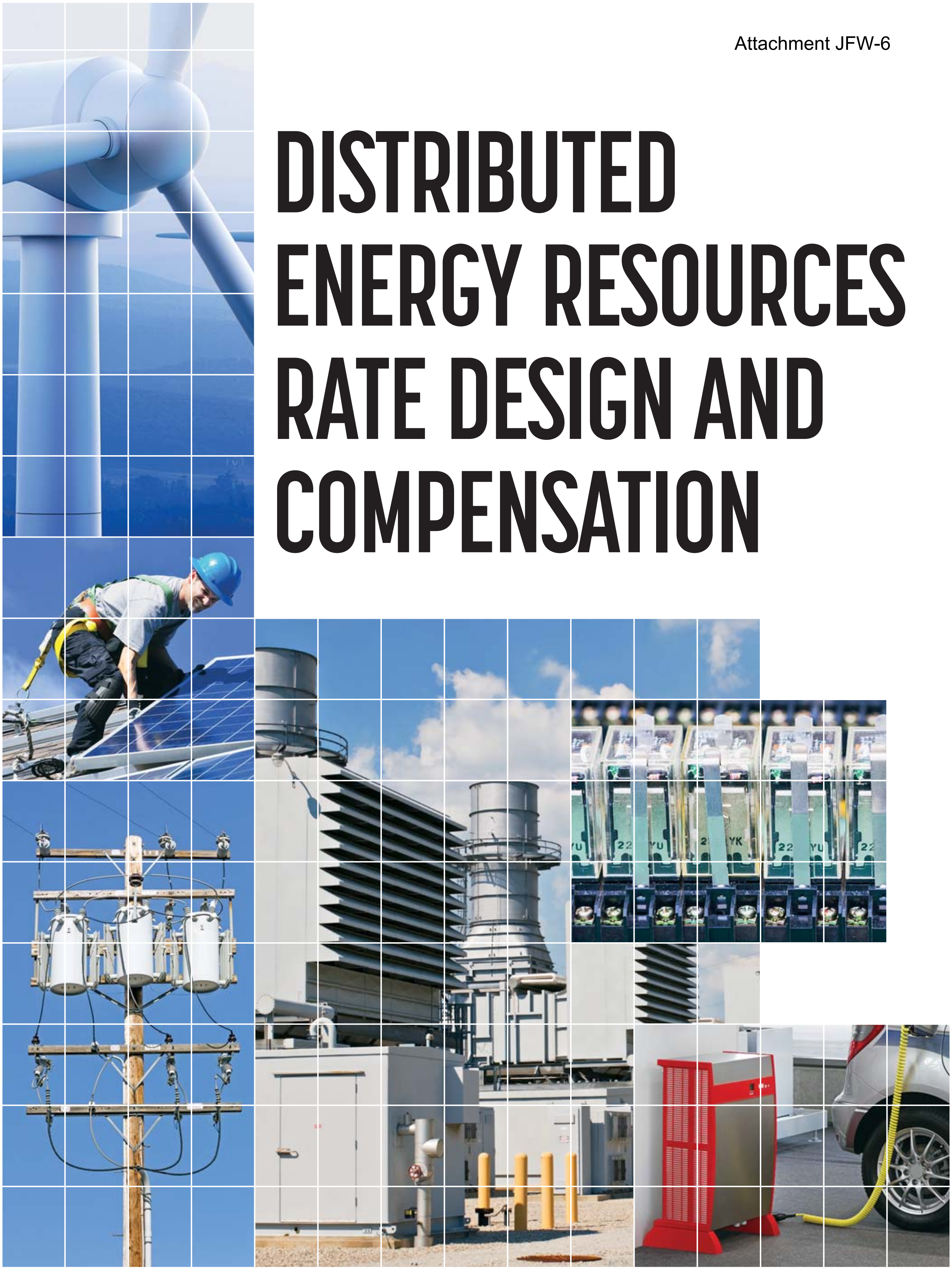
Midwest

Customers	Heat Pump or A/C
1	1
2	.8
3	.6
4	.5
5	.45
6 & up	.4

Witness: Diaz for a-c, Abbott/Hart for d-e.

ATTACHMENT JFW-6

DISTRIBUTED ENERGY RESOURCES RATE DESIGN AND COMPENSATION



A Manual Prepared by the NARUC Staff Subcommittee on Rate Design

November 2016

increasing cost shift of what they view as fixed costs from DER customers to other customers as an extension of previous justifications for fixed-charge increases.[172]

Higher fixed charges accomplish the goal of revenue stability for the utility and, depending on the degree to which one agrees that utility costs are fixed, match costs to causation. However, the interplay between collecting more costs through a fixed charge and the volumetric rate may result in uneconomic or inefficient price signals. Indeed, an increase in fixed charges should come with an associated reduction in the volumetric rate. Lowering the volumetric charge changes the price signal sent to a customer, and may result in more usage than is efficient. This increased usage can lead to additional investments by the utility, compounding the issue.[173]

This potentiality also highlights the disconnect between costs and their causation that a higher fixed charge may have. If higher usage leads to increased investment, then it may be appropriate for the volumetric rate to reflect the costs that will be necessary to serve it, which would point toward the appropriateness of a lower fixed charge. In other words, it may be more reasonable to lower the fixed costs and increase the volumetric rate, which would send a more efficient price signal.

A related movement is the adoption of a minimum bill component. California, which does not have a fixed charge component for residential customer bills, adopted a minimum bill component to offset concerns raised by its regulated utilities regarding the under-collection of revenue due to customers avoiding the costs of their entire electric bill and not having a balance owed to the utility at the end of the month.[174] In other words, some NEM customers in

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172 For details on fixed charge proposals and decisions across the country, *see* NC Clean Energy Technology Center's *The 50 States of Solar Report* (https://nccleantech.ncsu.edu/?s=50+states+of+solar&x=0&y=0), which is updated quarterly.

173 Synapse Energy Economics Inc., "Caught in a Fix: The Problem with Fixed Charges for Electricity" (Synapse Energy Economics Inc., Cambridge, MA, February 9, 2016), 18.

174 *Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations*, "Decision on Residential

ATTACHMENT JFW-7

POWELL GOLDSTEIN LLP

Principles of Public Utiliity Rates by James C. Bonbright

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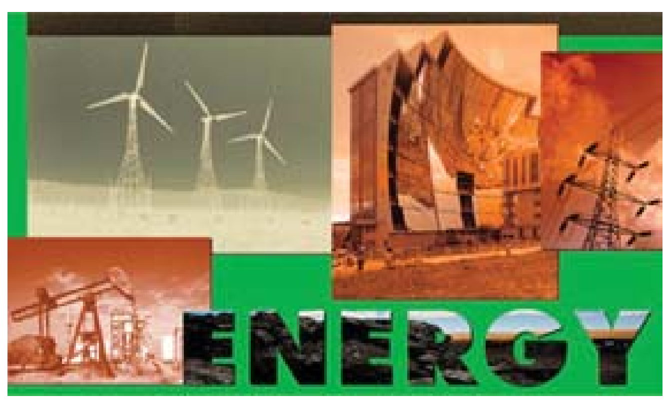

COMPLICATION OF PLANT INDIVISIBILITIES

One further complication of long-run marginal-cost determination is that which arises because of the literal or practical indivisibility of some of the "factors of production"—particularly, of some of the larger units of plant and of heavy equipment.

In the *simpler* expositions of the behavior of the costs of a business enterprise in response to increases in rates of output, *continuously* rising output curves and total-cost curves are assumed—curves in which total cost rises smoothly with, though not necessarily proportionately to, the increasing rates of output. With rapidly expanding public utility systems, this assumption of continuity may give a sufficiently close approximation to the real-life uptrends in total costs to serve the purposes of rate determination. But at times the discrepancies between this assumption and actual cost behavior become serious enough to be of concern to the rate maker. These are times when plant expansion, either as a matter of utter necessity or as a matter of good economy, takes place in fairly large jumps.

The classic example of such a jump is that of a railroad which expands its line-haul capacity by shifting from a single to a double track. But many similar examples apply to the expansion of the urban utilities. Thus, in order to take advantage of the recognized economies of large-scale turbogenerators, an electric company may plan its program of expansion so that its output will first encroach on its reserves pending the completion of a gigantic generating unit, after which time the reserve may be excessive for the next year or more. And thus a telephone, electric, or gas company, in order to minimize the long-run costs plus the inconveniences of network installations involving the tearing up of city streets, may install all at once distribution capacity adequate for an estimated growth in load over the next several years.

Under these circumstances of a "jumpy" program of plant expansion, how does one measure the marginal costs of supplying the service? If the question concerns the determination of short-run marginal costs, the answer is relatively simple. Marginal costs of this type ignore capital costs in any event, regardless of the rate of expansion. Hence, if an electric utility company has just put into operation a gigantic turbogenerator which makes its power capacity temporarily excessive, marginal cost will drop correspondingly, only to rise again as the increase in plant utilization shifts from one of redundancy to one of shortage of reserve capacity. If utility rates were to follow these changes in short-run marginal costs, they too would rise and fall like waves—clearly an impractical situation.

But if our concern is to determine *long-run* marginal costs—incremental unit costs that may be expected to remain relatively stable despite temporary changes from situations of plant overcapacity to plant undercapacity—the problem is not so easy. Here, one must attempt some estimate of *average* incremental costs per unit of output over the life of the indivisible asset. This possible solution is fraught with difficulties. But so, for that matter, is the solution of *any* problem of long-run utility cost imputation.

SHORT-RUN VERSUS LONG-RUN MARGINAL COSTS AS MEASURES OF MINIMUM RATES

Having noted in the preceding section the very striking differences that are likely to prevail at any given time between short-run and long-run marginal costs, we may now consider the relative importance that should be attached to these two types of cost in the design of the rate structure. The question takes on a sharper form when raised under a proposal that all rates be fixed at mere marginal cost—a proposal to be discussed in Chapter XX—than it does when raised subject to the constraint that rates as a whole must be made to cover total costs. But we may discuss the question here under the assumption of this constraint and with reference to the use of marginal cost or incremental cost as a measure of *minimum* rates. Unfortunately, no simple answer to this question of choice is acceptable, since it presents one of the many dilemmas of rate-making policy.

THE CASE FOR SHORT-RUN MARGINAL COSTS

The argument in favor of short-run marginal costs as a basis of minimum rates can be stated briefly by the proposition that the costs which should govern the rates to be charged at any given time are the costs that actually prevail at this time and not the costs that will or would prevail on the average during an indefinite decided effect on those decisions of potential customers which will govern their future uses of utility services. But this effect will depend primarily on consumers' assumptions that the currently published rates, even if subject to fractional increases or decreases as a result of a new rate case, will not undergo a change in their general orders of magnitude or in their general relationship to the prices of substitute services or commodities.

In view of the above-noted importance attached to existing utility rates as indicators of rates to be charged over a somewhat extended period in the future, one may argue with much force that the cost relationships to which rates should be adjusted are not those highly volatile relationships reflected by short-run marginal costs but rather those relatively stable relationships represented by long-run marginal costs. The advantages of the relatively stable and predictable rates in permitting consumers to make more rational long-run provisions for the use of utility services may well more than offset the admitted advantages of the more flexible rates that would be required in order to promote the best available use of the existing capacity of a utility plant.

The history of railroad and utility rate regulation in this country would supply numerous examples of the dangers of especially low "incremental cost" rates which, at the time of their establishment, seemed well justified by their compensatory character but which, at a later time, failed to cover even their out-of-pocket costs.[14] What happened here is that the low rates, originally designed to promote greater use of a temporarily redundant plant, helped to stimulate demand to such an extent that the plant became inadequate, with the result that the incremental or marginal costs of the service rose to levels equal to or even above average total costs. Such a situation arose in New York State and elsewhere

[14] On the danger of promotional rates based on temporarily low incremental costs, see Hubert F. Havlik, *Service Charges in Gas and Electric Rates* (New York, 1938), pp. 59–60. This danger was emphasized by Milo R. Maltbie during his chairmanship of the New York Public Service Commission, e.g., in N.Y. Central R.R. Co. Rates (Commutation Fares), Case 6533, P.U.R. 1932C 75. Mr. John Alden Bliss, a transportation economist, calls my attention to a classic example of this danger in railroad rate making: namely, to James J. Hill's low eastbound lumber rates, which finally created a new eastbound peak and a consequent need to haul empties westbound. "Such low rates," writes Mr. Bliss, "are difficult to correct, even without presuming regulation." The influence of vested interests in established railroad-rate relationships is discussed by Professor I. L. Sharfman, *The Interstate Commerce Commission*, Vol. III B (New York, 1936), pp. 667 *et seq.*

with respect to the manufactured-gas companies, which at one time offered sharply reduced rates to users of the gas for house heating in order to put to fuller use plants that had been made redundant by the competition of electricity. Even before the coming of natural gas, house-heating use in some areas had enhanced the demand for manufactured gas beyond the capacity of the existing plants, with the result that the heating rates ceased to be compensatory. The companies sought, and finally secured, permission from the public service commission to raise these rates; but only after a considerable delay, during which time consumer spokesmen complained that they had installed gas furnaces "on the faith" of the persistence of the favored rates.

But one should not conclude from the foregoing remarks that the danger from rates based largely on temporarily low, short-run marginal costs is a danger never worth running. Indeed, something can be done to minimize the danger through the issuance by a public utility company and by a regulatory agency of clear-cut warnings that especially low rates, designed to make the best feasible use of temporarily excessive plant capacity, are subject to cancellation on very short notice. Thus, during the 1930s, the Ontario Hydro-Electric Power Commission, which supplies the Province of Ontario with most of its electric power and which was then faced with a gross excess in water-power capacity, granted phenomenally low temporary rates to industries which used the power to heat boiler water and to serve other "low-grade" purposes. Indeed, the familiar American use of low rates for "interruptible power" (interruptible within limitations) and of still lower rates for "dump power" (interruptible with few if any limitations) serves the same general purpose.

As to the possible use of a high short-run marginal cost as a measure of rates when the existing capacity of a utility system will not suffice to supply all service that would be demanded at "normal" rates of charge, the practical and political objections to this practice have been deemed so serious that resort to overt rationing or to the policy of first come, first served has been the accepted alternative. For reasons suggested in an earlier chapter,[15] these objections seem to me not merely serious but almost fatal if the public utility in question is operating under private ownership.

[15] Pp. 98–99, *supra*.

I conclude this chapter with the opinion, which would probably represent the majority position among economists, that, as setting a general basis of minimum public utility rates and of rate relationships, the more significant marginal or incremental costs are those of a relatively long-run variety—of a variety which treats even capital costs or "capacity costs" as variable costs. Short-run marginal costs should not be ignored. But they should be used with caution, and with special warnings of the liability of rates based thereon to cancellation or revision on short notice.

XVIII

FULLY DISTRIBUTED COSTS

As already noted in Chapter XVI, writers on the economic principles of public utility rates have suggested that, when the rates of any given utility enterprise must be made to cover total costs of production even though the enterprise is operating under conditions of declining unit costs (of unexhausted economies of scale), each individual rate should be made up of two components: a minimum price set at the marginal cost of the service, and a surcharge or quasi tax designed to contribute some appropriate share of those additional revenue requirements which would fail to be covered if all rates were to be held down to their minima. While even the surcharge would not be independent of marginal cost, its relationship thereto would not necessarily be a simple one and might well be deliberately "biased" by value-of-service considerations. The same idea is implicit in the more popular but cruder assertion that public utility and railroad rates should be set somewhere between "cost of service" (that is, out-of-pocket or marginal costs) as a lower limit and "value of service" (that is, what the traffic or market will bear) as an upper limit.

In actual practice, however, rate structures are seldom built up in this two-step manner. Instead, if based on any comprehensive cost analysis at all (which appears to be true in only a tiny minority of cases) they are derived analytically, not synthetically, from apportioned total costs of service. Thus, with an electric utility company, the analyst may first distribute total annual costs among nine classes of service, more or less: residential, commercial, industrial power, street lighting, etc. He may then redistribute the costs of each class among the units of service within this class, distinguishing among customer units, energy units (kilowatt-hours), and

ATTACHMENT JFW-8

The Economics of Regulation
Principles and Institutions

Volume I Economic Principles
Volume II Institutional Issues

Alfred E. Kahn

The MIT Press
Cambridge, Massachusetts
London, England

Second Printing, 1989

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permitting prices to fluctuate widely along the SRMC function, depending on the immediate relation of demand to capacity,[49] the practically achievable benchmark for efficient pricing is more likely to be a type of average long-run incremental cost, computed for a large, expected incremental block of sales, instead of SRMC, estimated for a single additional sale. This long-run incremental cost (which we shall loosely refer to as long-run marginal cost as well) would be based on (1) the average incremental variable costs of those added sales and (2) estimated additional capital costs per unit, for the additional capacity that will have to be constructed if sales at that price are expected to continue over time or to grow.[50] Both of these components would be estimated as averages over some period of years extending into the future.

5. The prevalence of common costs has similar implications. Service A bears a causal responsibility for a share of common costs only if there is an economically realistic alternative use of the capacity now used to provide it, or if production of A requires the building of additional capacity. The marginal opportunity cost of serving A depends on how much the alternative users would be willing to pay for devoting the capacity to serving them instead. The sum of the separable marginal costs will therefore cover the common costs only if at separate prices less than this the claims on the capacity exceed the available supply.[51]

6. Long-run marginal costs are likely to be the preferred criterion also in competitive situations. Permitting rate reductions to a lower level of SRMC, which would prove to be unremunerative if the business thus attracted were to continue over time, might constitute predatory competition—driving out of business rivals whose *long-run* costs of production might well be lower than those of the price-cutter.

SRMC on the average equal to its composite ATC—running far above ATC when operations exceeded the 80% level and correspondingly below at other times. See pp. 94–97, Chapter 4, below.

[49] If SRMC pricing did not cover ATC over time, capital would eventually be withdrawn and new capital, needed to meet the rising demand, repelled, until a recovering demand, moving up along a steeply rising MC curve, pushed prices up high enough and held them there long enough to attract new capital into the industry—with the possibility of a return of depressed prices with any temporary reemergence of excess capacity. In the case of the partly-empty airplane (see pp. 75–76), the "efficient price" would be zero as long as the response of travelers remained insufficient to fill the plane; then it would have to jump the moment the empty spaces fell one short of demand, possibly to the full cost of an added flight but in any case to whatever level necessary to equate the number of available seats with the number of would-be passengers. On each flight, the available seats would have to be auctioned, with the uniform price settling at the point required to clear the market.

[50] See W. Arthur Lewis, *Overhead Costs* (New York: Rinehart, 1949), 15–20; Marcel Boiteux, "Peak-Load Pricing" in James R. Nelson, *Marginal Cost Pricing in Practice* (Englewood Cliffs: Prentice-Hall, 1964), 70–72.

[51] As we have just seen in another connection (pp. 82–83), the marginal opportunity cost of providing a cubic foot of warehouse space to any particular user, A, is the most valuable alternative use of that space excluded by serving A—what the most insistent excluded customer would have been willing to pay for it. If at any price per foot less than the proportionate share of the common costs (that is, less than ATC) of the warehouse, there are or would be unsatisfied customers—that is, more cubic feet demanded than were available—then clearly the marginal opportunity cost of each cubic foot would be at least equal to average total costs, and prices correctly set at SRMC would cover total costs. If, instead, at a price equal to ATC there is excess capacity, this demonstrates that price exceeds marginal opportunity costs: serving A is not preventing anyone else willing to pay that much from getting all the space he wants. In this circumstance, prices set lower, at true SRMC, would not provide enough revenue to cover total costs.

ATTACHMENT JFW-9

PUBLIC UTILITY ECONOMICS

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flat rate is now little
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is possible to estimate
with reasonable accu-
flat-rate type of rate
bill remains the same
kilowatt-hours con-
average effective rate
of electric energy used
eased use. Flat rates
phone companies for

local exchange service and by urban transit utilities. Their services are supplied under circumstances which make this the most feasible form of pricing.

(2) *Straight-Line Meter-Rate Schedules.* Straight-line meter-rate schedules provide service at a constant charge per metered unit of energy, regardless of the quantity of energy used. For example, the rate schedule might provide for a charge of 4 cents per kilowatt-hour. Under this type of rate schedule, the average rate per kilowatt-hour remains the same regardless of the amount consumed, but the customer's bill increases proportionately with the increase in energy used. This type of rate schedule is used in some cases for off-peak water heating and special services; however, it has been largely abandoned for general use. The advantage of this type of rate schedule is its simplicity. The principal weakness is that it does not provide any rate reduction or incentive for larger volume use.

(3) *Block Meter-Rate Schedules.* The block meter-rate schedule is now the type most widely used for residential and other small-volume consumers. This type of rate schedule offers a decreasing price per unit of energy for successive blocks (quantities) of consumption. More specifically, this type of rate schedule offers successively lower rates per kilowatt-hour for all or part of each block of energy consumed. The customer's bill is calculated by cumulating the charges incurred for each successive block of energy taken or fraction thereof. This example illustrates a block meter-rate schedule for monthly billing; the minimum charge is $1.05.

First 10 Kwh or less	$1.05
Next 30 Kwh	4.5 cents per Kwh
Next 60 Kwh	3.9 cents per Kwh
Next 100 Kwh	2.7 cents per Kwh
201 Kwh or more	2.0 cents per Kwh
Minimum charge, $1.05 per month	

The block meter-rate schedule is simple and easily understood by consumers. The average over-all rate charged per kilowatt-hour declines with increased use, thus promoting sales. The bill increases more or less proportionately to energy used within each block but less than proportionately when all consumption beyond the first block is considered.

The block meter-rate schedule, and others, may include either a "service charge" or a "minimum charge." There is an important difference between the two. The *service charge* is a fixed amount per month, say 75 cents, that a customer must pay, regardless of the consumption of energy, and for which he can use no energy. The *minimum charge,* on the other hand, is based upon a minimum amount of consumption which the customer will have to pay for—whether or not that amount is actually used. Thus, the minimum charge permits the utility to collect some amount from the convenience user without increasing the bill of the average customer. In the above illustration of a block meter-rate schedule, for example, a minimum charge of $1.05 per month is related to the first block of 10 kilowatt-hours. Any monthly total consumption of less than that amount would be billed at $1.05 nonetheless. In summary: (a) the service charge is a fixed monthly sum that is unrelated to any specified quantity of consumption; while (b) the minimum charge is a fixed monthly sum that is related to a specified minimum monthly consumption of energy which the customer must pay for whether it is used or not. Where the rate schedule calls for a service charge, the block charges are ordinarily lower than in rate schedules providing a minimum charge.

The purpose of both the service charge and the minimum charge is to cover at least some of the costs incurred by the utility whether or not the customer uses energy in a particular month. For small customers under the block meter-rate schedule, a charge of this kind is intended to cover the expenses relating to meter service and maintenance, meter reading, accounting and collecting, return on the investment in meters and the service lines connecting the customer's premises to the distribution system, and others. Such expenses as these represent as a minimum the "readiness-to-serve" expenses incurred by the utility on behalf of each customer. In the absence of a service charge or minimum charge, these expenses would be avoided by the convenience user and transferred unfairly to those consuming service.

In some states there has been public protest against the service charge, largely on the ground that it permitted the utility to receive "something for nothing." This type of public opinion has arisen because no energy use is related to the service charge. Accordingly, some state commissions have prohibited the service charge in favor of the minimum charge. The New York commission, for example, has recognized that the basis of the public opposition to the service charge ". . . is not so much economic or accounting as it is psychological." A different attitude was found to exist with respect to the minimum charge.[35]

A predecessor of the block meter-rate schedule, called the *step meter-rate schedule,* is now almost never used. Under this type of rate schedule one price was charged per unit of energy for the entire amount of service consumed. That unit price was determined by the price attaching to the particular block in which the total consumption happened to fall; prices decreased with each successive block. Because of this feature it was sometimes possible to reduce the over-all bill by wasting service so as to cause total consumption to come within the next, lower-priced energy block. The block meter-rate schedule, which cumulates block charges, was a substantial improvement.

(4) *Hopkinson Demand Rate Schedules.* The Hopkinson-type rate schedule is widely used for medium and large commercial and industrial customers. It was devised by Dr. John Hopkinson in 1892. The Hopkinson rate schedule provides for a two-part rate, consisting of separate charges for maximum demand and energy consumption. The customer's bill under this type of rate schedule, therefore, is the sum of the two components—the demand charge and the energy charge. As the Hopkinson-type rate schedule has been adapted for present-day use, either the demand charge or the energy charge or both may be graduated by blocks so as to provide lower charges for larger volumes of consumption. The Hopkinson-type rate schedule requires a measurement of kilowatts of demand and kilowatt-hours of energy. The rate schedule may provide that the customer's maximum demand be either measured or estimated. For larger customers, the maximum demand for billing purposes is generally obtained through measurement by use of a demand meter or demand indicator. The demand billing demand may be the maximum 15-minute or 30-minute demand measured in kilowatts as recorded in the billing month, or some similar measure of demand. The following is an illustration of a Hopkinson rate schedule for monthly billing.

Demand Charge:

$2.25 per Kw	....	first 2 Kw of demand
$2.00 per Kw	....	next 18 Kw of demand
$1.50 per Kw	....	next 80 Kw of demand
$1.25 per Kw	....	all over 100 Kw of de[illegible]

[35] *Re Rates and Rate Schedules of Corporations Supplying Electricity,* PUR 1931 C, 337, 347.

ATTACHMENT JFW-10

Duke Energy Indiana, LLC

Assignment of Uncollectible Expense to Residential Service for CAC 12.14 c

Uncollectible Expense	$8,214,796		
Applicable Rate Codes	RSN0	RSN2	TOTAL
Allocator: BILLING EXP NO OF CUST	0.78201919	0.04787239	0.82989158
Allocated Uncollectible Expense	$6,424,128	$393,262	$6,817,390
Number of Bills	8,510,599	514,959	9,025,558
Customer Charge Component per Bill			$0.76

ATTACHMENT JFW-11

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