

EXHIBIT NO. _____ (AML-16)
DOCKET NOS. UE-170033/UG-170034
2017 PSE GENERAL RATE CASE
WITNESS: AMANDA M. LEVIN

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY,

Respondent.

DOCKET NOS. UE-170033
and UG-170034 (*Consolidated*)

EXHIBIT AML-16 TO THE
CROSS-ANSWERING TESTIMONY (NON-CONFIDENTIAL) OF
AMANDA M. LEVIN
ON BEHALF OF NORTHWEST ENERGY COALITION, RENEWABLE NORTHWEST,
AND NATURAL RESOURCES DEFENSE COUNCIL
NON-CONFIDENTIAL

August 9, 2017

**BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO**

**In the Matter of the Application of Ohio)
Power Company for Authority to)
Establish a Standard Service Offer) Case No. 16-1852-EL-SSO
Pursuant to R.C. 4928.143, in the Form)
of an Electric Security Plan.)**

**In the Matter of the Application of Ohio)
Power Company for Approval of Certain) Case No. 16-1853-EL-AAM
Accounting Authority.)**

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

NATURAL RESOURCES DEFENSE COUNCIL

Resource Insight, Inc.

MAY 2, 2017

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EXHIBITS

- Exhibit PLC-1 Professional Qualifications of Paul Chernick.
- Exhibit PLC-2 Case No. 11-351-EL-AIR July 9, 2015 Cost of Service Filing
- Exhibit PLC-3 Case No. 11-351-ER-AIR, Schedule E3.1 (2011).
- Exhibit PLC-4 Company's Response to NRDC Set 1, INT-1.
- Exhibit PLC-5 Company's Response to NRDC Set 1, INT-14.
- Exhibit PLC-6 Company's Response to NRDC Set 1, RPD-5.
- Exhibit PLC-7 Externalities References.
- Exhibit PLC-8 Company's Response to NRDC Set 1, RPD-27.
- Exhibit PLC-9 Company's Response to NRDC Set 1, INT-12.
- Exhibit PLC-10 Company's Response to NRDC Set 1, INT-13.
- Exhibit PLC-11 Company's Response to NRDC Set 1, RPD-28.
- Exhibit PLC-12 Company's Response to NRDC Set 1, INT-10.
- Exhibit PLC-13 Company's Response to NRDC Set 2, INT-17.
- Exhibit PLC-14 Company's Response to NRDC Set 2, INT-19.
- Exhibit PLC-15 AEP Ohio's 2017 to 2019 Energy Efficiency/Peak Demand Reduction
(EE/PDR) Action Plan, June 15, 2016, Tables 4, 7 and 9.
- Exhibit PLC-16 Case No. 16-0574-EL-POR, Exhibit JFW-2, (Volume 2), Table 43.

1 **I. IDENTIFICATION & QUALIFICATIONS**

2 **Q: Mr. Chernick, please state your name, occupation, and business address.**

3 A: My name is Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water
4 St., Arlington, Massachusetts.

5 **Q: Summarize your professional education and experience.**

6 A: I received a Bachelor of Science degree from the Massachusetts Institute of
7 Technology in June 1974 from the Civil Engineering Department, and a
8 Master of Science degree from the Massachusetts Institute of Technology in
9 February 1978 in technology and policy.

10 I was a utility analyst for the Massachusetts Attorney General for more
11 than three years, and was involved in numerous aspects of utility rate design,
12 costing, load forecasting, and the evaluation of power supply options. Since
13 1981, I have been a consultant in utility regulation and planning, first as a
14 research associate at Analysis and Inference, after 1986 as president of PLC,
15 Inc., and in my current position at Resource Insight. In these capacities, I
16 have advised a variety of clients on utility matters.

17 My work has considered, among other things, the cost-effectiveness of
18 prospective new electric generation plants and transmission lines, retrospec-
19 tive review of generation-planning decisions, ratemaking for plant under con-
20 struction, ratemaking for excess and/or uneconomical plant entering service,
21 conservation program design, cost recovery for utility efficiency programs,
22 the valuation of environmental externalities from energy production and use,
23 allocation of costs of service between rate classes and jurisdictions, design of
24 retail and wholesale rates, and performance-based ratemaking and cost re-
25 covery in restructured gas and electric industries. My professional qualifica-
26 tions are further summarized in Exhibit PLC-1.

1 **Q: Have you testified previously in utility proceedings?**

2 A: Yes. I have testified over three hundred times on utility issues before various
3 regulatory, legislative, and judicial bodies, including utility regulators in
4 thirty-four states and six Canadian provinces, and two U.S. Federal agencies.
5 This testimony has included many reviews of utility avoided costs, marginal
6 costs, rate design, and related issues.

7 **Q: Have you testified previously before the Public Utilities Commission of
8 Ohio (the “Commission”)?**

9 A: Yes. I have testified five times before the Commission:

- 10 • In Cases No. 91-635-EL-FOR, 92-312-EL-FOR, 92-1172-EL-ECP, on
11 behalf of the City of Cincinnati on the treatment of demand-side
12 management (DSM) in the Cincinnati Gas and Electric Long Term
13 Forecast Report for 1992.
- 14 • In Case No. 95-203-EL-FOR, on behalf of the Campaign for an Energy
15 Efficient Ohio on cost-effectiveness tests for electric DSM.
- 16 • In Case 03-2144-EL-ATA, on behalf of Green Mountain Energy on the
17 pricing of standard-offer service.
- 18 • In Case No. 05-1444-GA-UNC, on behalf of the Ohio Consumers’
19 Counsel (OCC) on energy-efficiency analysis and planning.
- 20 • In Case No. 14-1693-EL-RDR, on behalf of Sierra Club, on AEP Ohio’s
21 proposed affiliate power purchase agreement.

22 I have also advised and assisted the Ohio Consumers’ Counsel and other
23 parties on a number of issues related to various Ohio utilities.

24 **II. INTRODUCTION**

25 **Q: On whose behalf are you testifying?**

26 A: I am testifying on behalf of the Natural Resources Defense Council.

1 **Q: What is the scope of your testimony?**

2 A: I evaluate and respond to the rate design component of Ohio Power
3 Company's ("AEP Ohio" or the "Company") amended electric security plan
4 (the "Amended ESP") that will modify the current ESP III and extend its
5 term through May 2024. While the Amended ESP includes a number of
6 issues, I confine my testimony to the Company's proposal to restructure its
7 residential rates. Specifically, the Company proposes to increase the base
8 residential customer charge by a total of \$10 over two phases: initially from
9 the current \$8.40 per month to \$13.40 per month, with a subsequent increase
10 to \$18.40 per month on January 1, 2018. The Company also proposes a
11 corresponding reduction in the distribution energy charge for residential
12 customers of about 0.97¢/kWh by 2018.

13 AEP Ohio's proposal would more than double the base customer charge
14 (a 119% increase from the current level) effective January 1, 2018, and
15 decrease the distribution energy charge by more than half (53%).

16 **Q: Please briefly summarize your conclusions regarding the Company's**
17 **proposal.**

18 A: It would inappropriately shift recovery of usage-related costs from the energy
19 charge to the customer charge, unreasonably dampen energy price signals,
20 discourage conservation by residential customers, and increase energy
21 consumption. It would also unjustly result in subsidization of high-usage
22 customers by low-usage customers and increase monthly bills for the vast
23 majority of AEP Ohio's residential customers. For these reasons, the
24 customer charge should not be increased in this proceeding.

25

26

1 **Q: What information did you review in preparing this testimony?**

2 A: I reviewed the Amended ESP, relevant prefiled testimony of Company
3 witnesses, filed Company schedules and tables, and relevant Company
4 responses to information requests. I also reviewed, among other things,
5 material from AEP Ohio's filings in 11-351-EL-AIR, and Ohio Revised
6 Code ("ORC") §4928.02.

7 **Q: How is your testimony organized?**

8 A: The remaining sections cover the following topics:

- 9 • In Section III, I provide a high level summary of AEP Ohio's proposal and
10 my concerns with the Company's rationale and the impacts the customer
11 charge increase will likely have on customers and their energy choices;
- 12 • In Section IV, I discuss the industry-standard principles that are commonly
13 applied when evaluating rate design changes, as well as relevant Ohio
14 energy policies that should be taken into account;
- 15 • In Section V, I introduce the basics of designing cost-based rates relevant to
16 AEP Ohio's proposal, including a discussion of the costs that are most
17 appropriate to include in the customer charge and energy charge. Further, I
18 analyze the proposed customer charge increase from a cost-causation
19 standpoint and conclude that it would result in inappropriate and
20 unnecessary cost shifts;
- 21 • In Section VI, I lay out the bill impacts and likely effects on energy use and
22 conservation that would occur if the Company's proposal were
23 implemented;
- 24 • In Section VII, I address AEP Ohio's other claims with regard to its rate
25 design proposal, including the assertion that a higher customer charge
26 would be helpful in moderating bill volatility. In addition, I address the fact

1 that AEP Ohio appears to know very little about its low-income customers
2 (particularly those who use less than the average amount of energy), and
3 has not addressed the regressiveness of its proposal for those customers and
4 other vulnerable Ohioans;

- 5 • In Section VIII, I discuss AEP Ohio’s revenue decoupling mechanism.
- 6 • In Section IX, I address my concern with the Company’s apparent
7 preference for residential demand charges; and
- 8 • Finally, in Section X, I summarize my recommendations.

9 **III. SUMMARY OF CONCERNS WITH RATE DESIGN PROPOSAL**

10 **Q: Why do AEP Ohio’s proposed changes in rate design matter?**

11 A: As I describe more fully throughout my testimony, the customer charge is
12 static and does not change from month to month, regardless of how much—
13 or how little—energy a customer uses. Thus, this charge cannot be lowered
14 by customer efforts to conserve energy, whether through energy efficiency
15 investment, home automation, greater care in energy use, or installation of
16 distributed energy resources such as rooftop solar. The increased customer
17 charge results in reductions in energy charges, sending inefficient price
18 signals to customers that tend to reward increased consumption.

19 In addition to these concerns, increasing the customer charge
20 inappropriately shifts distribution costs onto customers with below-average
21 energy use. Shifting such costs onto customers who do not cause them
22 reduces the equity of the rate structure.

23 **Q: Does AEP Ohio’s proposed \$18.40 customer charge represent the total**
24 **charge that residential customers will pay?**

25 A: No. It is important to take into account the numerous riders that AEP Ohio
26 adds to the customer charge. A range of current riders add about 43.3% to the

1 base customer charge, plus an additional \$1.01 per month from the
2 gridSMART Phase 1 Rider.¹ Taking into account these existing riders, the
3 current effective customer charge is already \$13.05 per month—nearly \$5
4 above the stated base charge of \$8.40.² Thus, if the base customer charge
5 proposed by AEP Ohio were implemented in full (including all riders),
6 residential customers would effectively be paying \$27.40 per month in a
7 static, unchangeable charge as of January 1, 2018.³

8 Further, these riders increase over time. Workpapers filed by AEP Ohio
9 witness David Gill document an effective customer charge of \$29.71 by June
10 2018, including percentage adders totaling 52.6%, with similar increases in
11 subsequent years.⁴

12 **Q: What is AEP Ohio’s rationale for proposing such dramatic changes in its**
13 **residential rate design?**

14 A: The increase in the customer charge is proposed in the testimony of AEP
15 Ohio witness Andrea Moore (at 12–14). Her rationale includes three parts.
16 First, she asserts that:

¹ The riders that are computed as a percentage of base rate charges are the Residential Distribution Credit (–3.6%), Deferred Asset Phase-In (7.7%), Economic Development Cost Recovery (1.1%), Enhanced Service Reliability (7.3%) and Distribution Investment (29.0%). Those adders are also shown in the Bill Calculation Spreadsheets on the Company web site (www.AEPohio.com/account/bills/rates/AEPOhioRatesTariffsOH.aspx). Similar, but slightly different, values are shown in hidden columns in the spreadsheet form of AEP Ohio witness David Gill’s Workpaper DRG-7, in the “SSO Impacts” tabs.

² Current residential base customer charge [\$8.40] + (\$8.40 × percentage rider increase [0.433]) + gridSMART Phase 1 Rider [\$1.01] = \$13.05/month.

³ Proposed residential base customer charge [\$18.40] + (\$18.40 × percentage rider increase [0.433]) + gridSMART Phase 1 Rider [\$1.01] = \$27.40/month.

⁴ See David Gill spreadsheet workpaper for Exhibit DRG-7 (typical Bill impacts DRG-7.xlsx). Mr. Gill documents an effective total charge for a customer with zero consumption to be \$29.71 in June 2018, rising to \$32.18 in 2019, \$33.68 in 2020, and \$34.92 in 2021.

1 The Company filed, in Case No. 11-351-EL-AIR, an updated cost of
2 service study showing that a full customer charge should be \$27.24 for a
3 standard residential customer. While it is appropriate to move customers
4 towards the full customer charge, the Company is proposing to
5 implement this charge in a gradual fashion.

6 Distribution costs are incurred by sizing the distribution system to meet
7 customer(s) peak kW demand usage. These costs vary by peak demand
8 requirements, not by kWh usage or by simply connecting a customer to
9 the system. These costs would ideally be collected through a demand
10 charge, but this cannot be done for all customers due to the current
11 limitations of the Company's metering infrastructure.⁵

12 Second, she observes that “by removing a portion of the fixed costs
13 from the energy charge, some customers will see less volatility in bills from
14 high usage months, especially customers who use electric heat.”⁶

15 Third, Ms. Moore asserts that:

16 Another benefit from this design is that Percentage of Income Payment
17 Plan customers in 2014 and 2015 have used on average slightly over the
18 break even kWh for the customer charge of 1,030 kilowatt hours. This
19 proposal will lower the PIPP bills, therefore lowering the future revenue
20 requirement of the Universal Service Fund.⁷

21 **Q: What is your opinion of AEP Ohio’s proposed increase in the residential**
22 **customer charge?**

23 A: The Company’s proposal is not in the public interest, as it would yield a rate
24 design that is inequitable, inefficient, and regressive, in contravention of a
25 host of long-standing ratemaking principles and Ohio energy policy. What
26 limited rationale AEP Ohio offers is inadequate and at times misleading,
27 particularly given the significant impacts of the proposal on customers.

⁵ Moore Direct at 13.

⁶ *Id.*

⁷ *Id.*

1 While I describe these issues in detail in later portions of this testimony, the
2 following is a brief summary of my main concerns:

- 3 • As discussed in Section V, AEP Ohio’s proposal would inappropriately
4 shift costs from high-use customers to those who use less than the
5 average energy—without sufficient cost basis. The proposed \$18.40 per
6 month customer charge is much higher than the costs that should
7 appropriately be collected through this charge. The customer charge
8 should include only those costs of connecting an additional customer to
9 the distribution system. That value is likely already close to (if a bit less
10 than) the current base customer charge of \$8.40 per month. Thus, no
11 increase is warranted.
- 12 • As discussed in Section VI, the proposed rate design restructuring
13 would have a number of detrimental impacts on customers. It would
14 increase monthly bills for about 65% of the residential class. Further, it
15 would impact clean energy efforts in contravention of state policy, by
16 decreasing the ability and incentives for customers to manage their
17 electric bills, through energy conservation. Unfortunately the Company
18 has taken little to no steps to address these impacts, particularly for low-
19 income or other at-risk customers. Further, as discussed in Section VII,
20 the Company knows precious little about its low-income customers,
21 save for the limited cross-section of Ohioans that participate in the PIPP
22 program. And while the Company offers that some of these customers
23 may experience less volatility in bills with a customer charge increase,
24 this is of dubious benefit given the equity and clean energy impacts of
25 the proposal.
- 26 • As discussed in Section VIII, no customer charge increase is necessary
27 to stabilize AEP Ohio’s revenues, since the Company already has a

1 decoupling rider in place, in the Pilot Throughput Balancing Adjustment
2 Rider (the “PTBAR”). The PTBAR ensures that the Company collects
3 the Commission-authorized revenue requirement annually and—in
4 contrast to a customer-charge increase—maintains the price signal for
5 customers to conserve energy.

- 6 • Finally, as discussed in Section IX, AEP Ohio appears to be creating the
7 narrative for a future rate design in which demand-related a portion of
8 residential distribution costs would be collected through a residential
9 demand charge. Demand charges for the residential class are untested
10 and should be viewed with caution. They do not charge residential
11 customers for their usage at the times that contribute to the costs of the
12 distribution system, and do not provide useful incentives for customers
13 to reduce the burdens they impose on the system.

14 IV. THE GOALS OF RATE DESIGN

15 A. *Standard Ratemaking Principles*

16 **Q: Please describe some of the principles that are usually referenced in**
17 **designing rates.**

18 A: An industry standard reference for ratemaking concepts, *Principles of Public*
19 *Utility Rates* by James C. Bonbright (1961, at 291), lists the following
20 criteria for a “desirable rate structure,” a term that Bonbright uses broadly to
21 describe rate design, revenue allocation, and some aspects of setting the
22 revenue requirement:⁸

⁸ The entire 1961 version of *Principles of Public Utility Rates* is available at:
media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf

- 1 1. The related, “practical” attributes of simplicity, understandability,
2 public acceptability, and feasibility of application.
- 3 2. Freedom from controversies as to proper interpretation.
- 4 3. Effectiveness in yielding total revenue requirements under the fair-
5 return standard.
- 6 4. Revenue stability from year to year.
- 7 5. Stability of the rates themselves, with a minimum of unexpected
8 changes seriously adverse to existing customers.
- 9 6. Fairness of the specific rates in the apportionment of total costs of
10 service among the different consumers.
- 11 7. Avoidance of “undue discrimination” in rate relationships.
- 12 8. Efficiency of the rate classes and rate blocks in discouraging wasteful
13 use of service while promoting all justified types and amounts of use:
14 a) in the control of the total amounts of service supplied by the
15 company:
16 b) in the control of the relative uses of alternative types of service (on-
17 peak versus off-peak electricity...).

18 **Q: How do these Bonbright criteria apply to the rate design issues in this**
19 **case?**

20 A: Criteria 1 and 2—simplicity and clarity—are important, but tend to be non-
21 controversial: rate designs should be understood by customers and easy to
22 administer. As I discuss in Section IX **Error! Reference source not found.**
23 of this testimony, the potential application of demand charges to small
24 customers is an example of a rate design that would create challenges for
25 customer understanding.

26 Criteria 3 and 4—revenue adequacy and stability—concern the
27 determination of the revenue requirement and updating that requirement to
28 reflect changes in costs and sales. For AEP Ohio, a variety of adjustments
29 allow the Company to recover its authorized revenue requirement between
30 rate proceedings, including the existing PTBAR and reconciling adders.

1 Criterion 5—rate stability or gradualism—is satisfied by any rate design
2 that does not change abruptly. AEP Ohio’s proposal to more than double the
3 residential customer charge by January 1, 2018 would violate this principle.⁹

4 Criteria 6 and 7 require that the allocation of revenue requirements
5 among classes be “fair” and avoid “undue discrimination.” The resulting
6 standard is far from a requirement of precise revenue allocation, since “fair”
7 and “undue” are subjective terms. These criteria can also be read as applying
8 those standards to the rate design that spreads costs among customers within
9 a rate class. Because AEP Ohio’s proposal would shift costs incurred by and
10 for higher-use customers to low-use customers (as I discuss in Section VI.A),
11 it does not meet this fairness criterion.

12 Criterion 8 focuses the rate-design process on providing efficient price
13 signals. AEP Ohio’s proposal to offset the increase in the customer charge by
14 reducing the energy charge would create inefficient price signals and thus
15 would not meet this standard (as I discuss in Section VI.B).

16 Table 1 summarizes the Bonbright criteria and their application to AEP
17 Ohio’s proposal and residential rate design more generally.

18
19
20
21
22
23

⁹ Specifically, regulators usually require gradualism in changes to rate design and cost allocation, spreading large increases over many years.

Table 1: Rate-Design Implications of Bonbright Criteria

Criterion	Implications for AEP Ohio Rate Design
1 Simple, understandable, acceptable, feasible	Avoid demand charges Explain any new rate designs clearly
2 Clarity	
3 Revenue level	Decoupling resolves these issues
4 Revenue stability	
5 Rate stability	Avoid abrupt changes in rate design, gradualism
6 Fairness	Charge customers for the costs caused by their use (e.g., low-use customers do not subsidize high use)
7 No undue discrimination	Keep charges simple and consistent
8 Efficiency	Recover distribution costs in proportion to a customer's usage of the system, ideally by time varying rates

B. Relevant Ohio Policies

Q: What state energy policies are relevant to the Commission's review of AEP Ohio's rate-design proposal?

A: Ohio state energy policy is reflected in ORC §4928.02. Relevant to this proceeding, it provides for the following:

- ORC §4928.02(C) Ensure diversity of electricity supplies and suppliers, by giving consumers effective choices over the selection of those supplies and suppliers and by encouraging the development of distributed and small generation facilities;
- ORC §4928.02(D) Encourage innovation and market access for cost-effective supply- and demand-side retail electric service including, but not limited to, demand-side management, time-differentiated pricing, waste energy recovery systems, smart grid programs, and implementation of advanced metering infrastructure;
- ORC §4928.02(L) Protect at-risk populations, including, but not limited to, when considering the implementation of any new advanced energy or renewable energy resource.

1 **Q: Would AEP Ohio’s proposal be consistent with these provisions?**

2 A: No, as I discuss in Section VI, AEP Ohio’s proposal is unreasonably
3 burdensome and inequitable for the vast majority of residential customers. To
4 the extent a portion of those customers are low-income, that burden would
5 be heavily weighted towards at-risk populations. Further, the proposal yields
6 inefficient price signals that will discourage customers from making clean
7 energy choices—both in reducing their energy use and in making distributed
8 generation decisions— in contravention of Ohio energy policy.

9 **V. DESIGNING COST-BASED RATES**

10 **Q: How is this section organized?**

11 A: In the following sections, I break down the standard steps in setting cost-
12 based rates, including the formulation of customer and energy charges, and
13 make recommendations regarding the Commission’s consideration of those
14 charges for AEP Ohio’s residential customers. Understanding this framework
15 and how it relates to the rates that customers pay is important, since AEP
16 Ohio is proposing to shift substantial residential distribution cost recovery
17 from the energy charge to the customer charge.

18 **A. Fundamentals of Rate Design**

19 **Q: What are the relevant considerations in designing residential electric**
20 **rates?**

21 A: Residential electric rate design usually includes only a customer charge and
22 one or more energy charges.¹⁰ As discussed in more detail below, the

¹⁰ The energy charge may vary with usage (e.g., in an inclining-block rate, in which price rises with usage level), with season, and (where the customers have the necessary metering installed) with time of day. AEP Ohio has not proposed any differentiation of the energy charge or provided the data necessary for time variation, so I will assume in this discussion that there will be only one energy charge.

1 customer charge should reflect some measure of the cost of serving an
2 additional customer, the cost saved by reducing the number of customers, or
3 a fair share of the costs that result from the number of customers served,
4 independent of the amount of energy they use.

5 In contrast, the energy charge should reflect the costs that vary with the
6 amount of power delivered, independent of the number of customers served.
7 For an electric distribution utility, such as AEP Ohio, the costs of delivering
8 power are the costs of building and maintaining the distribution system.

9 **Q: What is the most straightforward approach to calculating residential**
10 **customer and energy charges?**

11 A: The simplest cost-based approach to determining the cost categories that
12 could appropriately be collected through the customer and energy charges
13 consists of the following steps:

- 14 • Add up the embedded revenue requirements attributable to the number
15 of customers and divide by the number of annual residential bills to
16 derive a customer charge in \$/customer-month.
- 17 • Add up the remainder of the revenue requirements and divide by the
18 residential energy sales, to derive an energy charge in ¢/kWh.

19 Embedded costs are generally used to allocate costs among rate classes,
20 as AEP Ohio did in the cost-of-service study in its 2011 rate case, Case No.
21 11-351-EL-AIR, part of which is reproduced in Exhibit PLC-3.

22 Variants on this approach reflect marginal costs: the cost of adding a
23 customer, the benefit of removing a customer, or the cost of reinforcing the
24 system to accommodate increased energy growth. Computing marginal
25 customer cost and marginal distribution energy cost is a significant

1 incremental effort, which neither AEP Ohio nor I have undertaken in this
2 case.

3 Once cost-based customer and energy charges are calculated, the next
4 step is to apply Bonbright's rate design principles and relevant state energy
5 policies. I discuss the application of these principles in the context of the
6 impact of AEP Ohio's proposal on customers and conservation in Section VI.

7

8 **B. AEP's Ohio's Overall Distribution Costs**

9 **Q: What costs are recovered through AEP Ohio's distribution rates?**

10 A: A utility distribution system generally consists of the following major classes
11 of equipment costs:

- 12 • Substations are primarily large transformers that step down transmission
13 voltages (such as 69 kV and 138 kV) to the distribution voltages of
14 2,400 V to 34,500 V.¹¹
- 15 • Feeders, or primary lines, typically serve hundreds or thousands of
16 customers, running miles from the distribution substation to the
17 locations of primary-voltage customers and the line transformers
18 serving secondary-voltage customers.
- 19 • The line transformers (usually cylinders on poles or rectangular boxes
20 mounted on concrete pads) step the primary voltage down to voltages
21 that can be used by residential and most other customers, which range
22 from 120 V to 480 V.

¹¹ These voltage levels are listed in the AEP Ohio Standard Tariff, posted at www.aepohio.com/global/utilities/lib/docs/ratesandtariffs/Ohio/2017-04-28_AEP_Ohio_Standard_Tariff.pdf

- 1 • From the line transformers, power flows directly to some customers
2 over service drops, and runs along the street (or other public way) on
3 secondary lines, to the service drops of other customers.
- 4 • The service drops, whether fed directly from the line transformer or
5 through secondary lines, run either overhead or underground from the
6 street to the customer’s home or other building. In the case of a
7 multifamily building, there will usually be one service drop to the
8 building.
- 9 • Power runs from the service drop through customer-owned wires to the
10 meter, and then on to the customer’s circuit breakers.

11 The costs of the distribution system consists of: 1) the interest, return,
12 taxes and depreciation associated with the capital investments; 2) operating
13 and maintenance (O&M) expenses; and 3) allocations of overhead and
14 general costs. The customer-related costs comprise the service drops, meters,
15 and expenses for maintaining that equipment; as well as the costs of meter
16 reading, billing, and otherwise dealing with customers. These costs are called
17 “customer accounts” and “customer service” costs in the FERC accounting
18 system.

19 C. *Setting the Customer Charge*

20 **Q: What distribution system costs should be attributed to the customer**
21 **charge?**

22 A: The primary challenge in rate design is to reflect the costs that customers
23 impose, both to encourage them to use utility resources responsibly and to
24 share costs fairly. The customer charge is intended to reflect the incremental
25 costs imposed by the continued presence of a customer who uses very little
26 energy. Thus, the customer charge should not be expected to cover all

1 customer-related costs for the average residential customer, but only the
2 incremental cost to connect one more very small customer.¹² Since AEP
3 Ohio would probably not need to add any secondary conductor or a
4 transformer to connect most of its very small customers (who would tend to
5 be in apartment buildings), incremental connection costs would be limited to
6 installation and maintenance costs for a service drop and meter, along with
7 meter-reading, billing, and other customer-service expenses.¹³

8 Further, given the narrow categories of costs that should be recovered
9 through the customer charge, the only useful price signals that a customer
10 charge provides are related to consumer decisions regarding whether to have
11 the Company install a meter (and whatever other equipment is necessary) and
12 whether to have AEP Ohio continue metering and billing a location where
13 the energy delivered is of very little value.

14 **Q: Should customer charges be based on average or incremental costs?**

15 A: While a number of considerations affect the choice of an appropriate
16 customer charge, the incremental costs—i.e. the costs of connecting an
17 additional customer to the distribution system—are the important costs for
18 giving customers signals regarding the cost of keeping them connected to the
19 system.

20 The average embedded customer-related cost is a convenient reference
21 value, however, even though it will usually be higher than an estimate of the

¹² See, e.g., Jim Lazar & Wilson Gonzalez, Smart Rate Design for a Smart Future, Regulatory Assistance Project, 36 (July 2015), available at www.raponline.org/wp-content/uploads/2016/05/rap-lazar-gonzalez-smart-rate-design-july2015.pdf.

¹³ Remote residences might also require a line extension and a small transformer in order to connect to the distribution system. On the other hand, customers located in a multi-family building would probably not require their own service drop.

1 incremental costs. The average embedded cost includes the costs of services,
2 meters, meter reading, billing, collections, other customer services, and
3 associated overheads. The billing system, the call center, and other expenses
4 are likely to have high fixed costs (e.g., the billing computers and software),
5 so the marginal cost of serving an additional customer is likely to be lower
6 than the embedded cost. The smallest customers are almost certainly
7 concentrated in apartment buildings, so adding an additional customer does
8 not require a service drop (since the building only requires one drop) and the
9 density of the customers reduces meter-reading costs, compared to suburban
10 single-family homes. Small customers will also have smaller bills and will be
11 less likely to bother contacting AEP Ohio's customer service operations.

12 **Q: Have either you or AEP Ohio calculated the cost of connecting an**
13 **additional residential customer?**

14 A: No. As indicated above, calculating marginal costs is a significant effort,
15 which neither AEP Ohio nor I have undertaken in this case.

16 **Q: What calculation do you propose to use instead?**

17 A: In Case No. 11-351-EL-AIR the Company calculated the average embedded
18 costs of serving residential customers (independent of usage). The
19 Company's Schedule E-3.1 in that proceeding, attached as Exhibit PLC-3,
20 shows a "Full Cost Customer Charge" of \$8.47/customer-month.¹⁴ While this
21 value would be higher than the incremental cost of adding an additional
22 customer, it appears to be a reasonable estimate of the average embedded

¹⁴ This cost was calculated in 2011 dollars. Some cost components have likely increased since 2011 (due to inflation and installation of additional advanced meters), while others have probably decreased (due to depreciation, amortization and reductions in meter-reading and other costs resulting from the advanced meters). The increases are recovered to some extent in riders, and might not affect an update of the base customer charge to 2017 or 2018.

1 cost and is close to the current base residential customer charge of \$8.40 per
2 month.

3 In arriving at this figure, AEP Ohio summed the following embedded
4 rate-base cost components:

- 5 • Services
- 6 • Meters
- 7 • General Plant and Intangible Plant
- 8 • Working Capital
- 9 • Materials and Supplies
- 10 • Pension Pre-payments

11 AEP Ohio subtracted rate base credits for Accumulated Depreciation,
12 Customer Deposits and net Deferred Taxes, and computed the revenues
13 necessary to cover the interest and equity return on the net rate base. To those
14 costs, AEP Ohio adds depreciation and amortization of the gross plant
15 values, as well as the following components of operations and maintenance
16 expenses:

- 17 • Meters
- 18 • Customer Installations
- 19 • Rents
- 20 • Miscellaneous Distribution
- 21 • Meter Reading
- 22 • Customer Records & Collection
- 23 • Uncollectible Accounts
- 24 • Interest on Customer Deposits
- 25 • Miscellaneous Customer Accounts
- 26 • Supervision and Engineering for distribution and customer service
- 27 • Administrative and General Expenses

1 The Company then divided the total residential customer-related costs
2 by the annual number of residential bills.

3 I note that this estimate of the customer-related costs is *less than a third*
4 of the \$27.24 per month value that Ms. Moore asserts should be reflected in
5 the customer charge.

6 **Q: What support does Ms. Moore give for the statement that “a full**
7 **customer charge should be \$27.24 for a standard residential**
8 **customer”?**¹⁵

9 A: Ms. Moore is referencing the Company’s updated July 2015 cost of service
10 study filed in Case No. 11-351-EL-AIR. This \$27.24 figure represents a
11 “Residential distribution charge of \$27.24 per bill” for a “Straight Fixed-
12 Variable rate design.”¹⁶ AEP Ohio explained in discovery responses that the
13 \$27.24 value is actually just the ratio of total residential distribution base
14 revenues, divided by the number of customer bills.

15 The \$27.24 represents the average base revenue per residential bill. The
16 residential base revenues that support the \$27.24 were presented in
17 Column K of Schedule E-4.1 in Case Nos. 11-351-EL-AIR and 11-352-
18 EL-AIR and were calculated using base rates at the time of that filing.
19 The total number of residential bills issued during the test period are
20 presented in Column C of the same schedules.¹⁷

21

¹⁵ Moore Direct at 13.

¹⁶ Ex. PLC-2.

¹⁷ Ex. PLC-4.

1 **Q: What costs are included in the \$27.24 per month that Ms. Moore says**
2 **should ideally be “the full customer charge...for a standard residential**
3 **customer”?**

4 A: In contrast to AEP Ohio’s 2011 estimate of \$8.47 per month in average
5 embedded customer-related costs, the \$27.74 value appears to include the
6 *entire* embedded distribution cost that AEP Ohio has allocated to the
7 residential class, divided by the number of residential customer months. The
8 \$27.24 thus includes the costs of substations, feeders and line transformers,
9 which are entirely or mainly driven by factors other than the number of
10 customers. It is inappropriate to include such costs in the customer charge.

11 Ms. Moore presents the \$27.24 value as if it were AEP Ohio’s estimate of
12 *customer-related* costs, but it is not. I see no analysis in the Company’s Amended
13 ESP filings, the 2011 rate case docket, or in discovery responses that parse out
14 which portion of these distribution costs should appropriately be considered
15 customer-related, and which should be considered demand-related. Rather, Ms.
16 Moore’s testimony implicitly assumes that *all* distribution costs should be
17 recovered through a fixed customer charge in dollars per customer-month,
18 independent of customer usage of the distribution system.

19 **Q: Do you agree that all distribution costs should be recovered through a**
20 **charge per customer-month?**

21 A: No. Some costs are driven primarily by the number of customers, and can
22 reasonably be collected through a charge per customer-month. Other costs are
23 determined by various measures of load, such as peak and near-peak loads on the
24 substations, feeders, line transformers and secondary lines. Energy requirements
25 prior to the peak hours also contribute to the sizing of equipment, and to the rate at
26 which equipment wears out. And some costs result from decisions to extend power

1 lines; those decisions are usually based on projections of revenue from the load on
2 the extended line, and are therefore due more to energy use than customer number.

3 **Q: Has AEP Ohio provided any argument for recovering additional costs**
4 **through the customer charge?**

5 A: When asked for AEP Ohio's basis for believing that "the proposed increase more
6 accurately reflects the cost causation from the customers' use of the distribution
7 system," the Company responded:

8 The cost of providing distribution service do not vary with volumetric
9 usage. Generally, the distribution system costs are affected by either
10 peak demand imposed on the distribution facilities or by the number of
11 customers served. If these costs are primarily recovered through an
12 energy charge, the customer is sent a price signal that by lowering their
13 usage they are lowering the cost imposed on the system even though
14 they have not necessarily lowered the costs imposed on the system.¹⁸

15 The same interrogatory asked AEP Ohio to "list the components of the
16 distribution system for which the Company believes that cost causation is
17 more accurately reflected by including the cost in a customer charge, rather
18 than in an energy charge." The Company did not identify any such
19 components of the distribution system.¹⁹

20 **Q: Does this response justify recovering distribution costs through the**
21 **customer charge?**

22 A: No. This response is incorrect in at least three ways. First, the cost of
23 providing distribution service really does "vary with volumetric usage." A
24 customer who uses large volumes of electricity will impose higher costs on
25 the system than one who uses very little power, unless they have very strange

¹⁸ Ex. PLC-5.

¹⁹ *Id.*

1 load shapes.²⁰ While a customer who increases energy use will probably—
2 even if not *necessarily*—have raised the costs imposed on the system, we
3 know that a customer who adds a meter without changing usage adds no
4 costs to the distribution system. Second, while total energy consumption is an
5 imperfect proxy for the costs imposed on the distribution system by a
6 customer, the customer charge has no correlation with contribution to
7 distribution costs. Third, while the price signal from a simple energy charge
8 is imperfect, the customer charge gives customers no useful price signal
9 regarding distribution costs.

10 **D. *Setting the Energy Charge***

11 **Q: How should residential distribution energy charges be set in order to**
12 **provide appropriate price signals and encourage conservation?**

13 A: Energy charges should be set at levels that recover costs that tend to increase
14 with customer usage. This includes the following three high-level cost
15 categories:

- 16 • Costs directly driven by customer usage, such as the costs of substations
17 and the sizing and number of distribution conductors and line
18 transformers.
- 19 • Costs driven by geographic expansion of the distribution system, which
20 in turn is driven by anticipated consumption and revenue.
- 21 • Costs that tend to be correlated with customer usage level but are not
22 directly caused by customer usage.

²⁰ The drivers of distribution costs would be best reflected by a time-of-use rate that spreads distribution costs among hours in proportion to the probability of substations, feeders, and transformers being heavily loaded. With the advanced metering that AEP Ohio has installed, identifying those hours and charging appropriate rates should not be difficult.

1 **Q: Concerning the first category, what usage factors directly increase the**
2 **costs of substations, conductors and line transformers?**

3 A: The cost of all these components are driven by a combination of the hours
4 with high loads on the equipment and the energy usage leading up to the high
5 loads.

6 **Q: How does energy consumption affect the life of distribution equipment?**

7 A: Existing distribution equipment wears out faster if it is more heavily loaded.
8 The capacities of transformers and underground power lines, in particular are
9 limited by the build-up of heat created by electric energy losses in the
10 equipment. Every time a transformer approaches or exceeds its rated capacity
11 (a common occurrence, since transformers can typically operate above their
12 rated capacity for short periods of time), its internal insulation deteriorates
13 and it loses a portion of its useful life. Long hours of high loads result in heat
14 building up in lines (especially underground lines) and transformers,
15 increasing the damage of peak loadings.

16 Figure 1 illustrates the effect of the length of the peak load, and the load
17 in preceding hours, on the load that a transformer can carry without losing
18 operating life.²¹ The initial load in Figure 1 is defined as the maximum of the
19 average load in the preceding two hours or 24 hours. A transformer that was
20 loaded to 50% of its rating in the afternoon can endure an overload of 190%
21 for 30 minutes or 160% for an hour. If the afternoon load was 90% of the

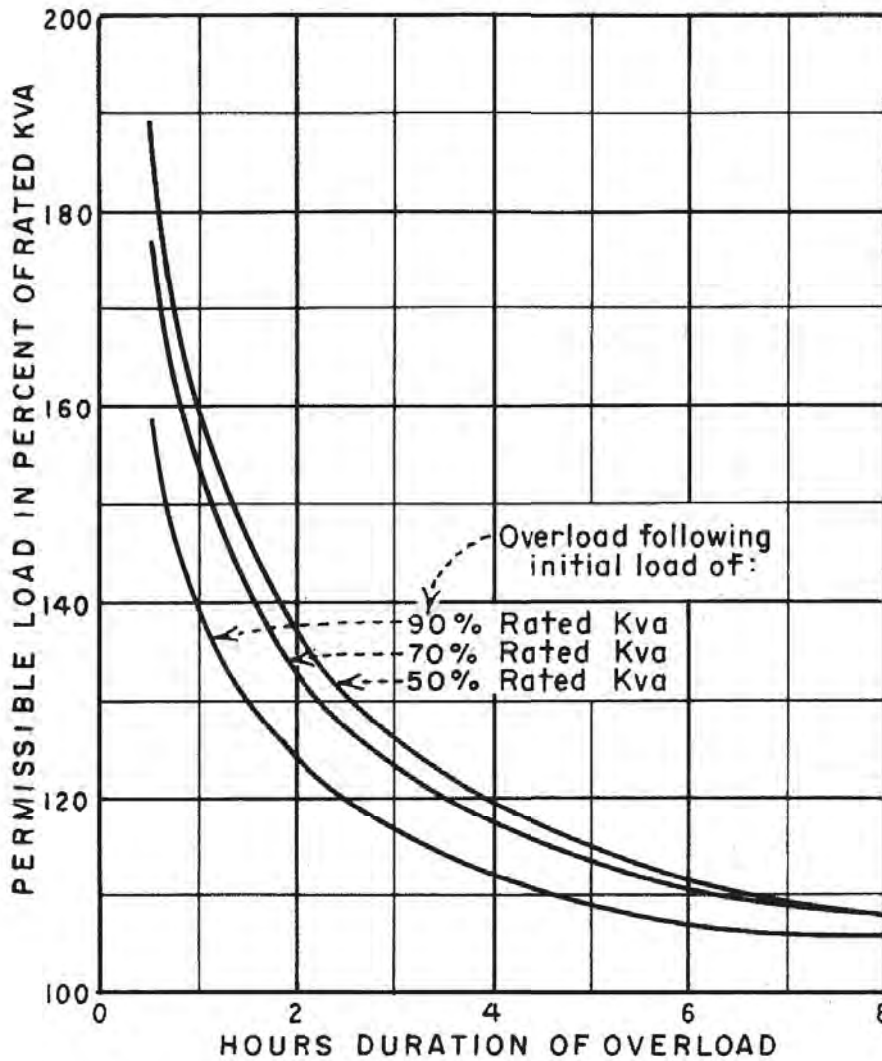
²¹ See *Permissible Loading of Oil-Immersed Transformers and Regulators*, United States Department of the Interior, Bureau of Reclamation, Facilities Engineering Branch, Denver Office, April 1991, available at www.usbr.gov/power/data/fist/fist1_5/vol1-5.pdf. This specific example is for self-cooled and water-cooled transformers designed for a 55°C temperature rise; other designs show similar patterns.

1 transformer rating, it could only carry 160% of its rated load for 30 minutes
2 or 140% for an hour.²²

²² Utilities recognize that the length of overloads is critical to determining whether a transformer needs to be replaced. For example, Exelon Maryland operating companies Potomac Electric Power (PEPCo) and Delmarva Power and Light have established standards for replacing line transformers when the average load over a five-hour period (determined from the reading on the advanced meters of the customers served by the transformer) exceeds 160% of the rating of overhead transformers or 100% for padmount transformers. See, e.g., testimony of Karen Lefkowitz at 41 in MD OPC Case No. 9418 (http://webapp.psc.state.md.us/newIntranet/Casenum/NewIndex3_VOpenFile.cfm?filepath=C:\Casenum\9400-9499\9418\Item_1\2016PepcoMDRateCaseApplicationDirectTestimonyandExhibitsVolIofII041616.pdf) or similar testimony in MD OPC Case No. 9424 (http://webapp.psc.state.md.us/newIntranet/casenum/NewIndex3_VOpenFile.cfm?filepath=C:\Casenum\9400-9499\9424\http://www.psc.state.md.us/) These major utilities have not found it necessary to establish comparable policies for shorter periods.

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Figure 1: Permissible Overload for Varying Periods



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Similarly, if the transformer's high-load period is three hours in the afternoon and evening, and the preceding load is 50% of rated capacity, the permissible load would be about 127% of rated capacity, but increasing the afternoon energy load and stretching the high-load period to eight hours would reduce the maximum loading to about 108%. Energy use in periods other than the transformer's peak hour can thus reduce the ability of the transformer to carry peak demands and force the replacement of the unit or addition of new transformers.

1 Alternatively, if the transformer is loaded heavily enough that the useful
2 life is reduced, reducing the pre-overload power flow and shortening the
3 overload period would mitigate that reduction, extending the life of the
4 equipment and reducing the rate of failure. This is particularly relevant for
5 line transformers, for which the utility will not usually be able to closely
6 monitor transformer loading and temperature.

7 **Q: Does heavy loading affect the capacity of underground lines?**

8 A: Yes. Heat builds up in conduit and around direct-buried lines, contributing to
9 overheating and damage to the lines' insulation.

10 **Q: Do the same issues apply to overhead lines?**

11 A: Yes, although the mechanisms are different than for the underground lines
12 and transformers. The capacity of overhead lines is often limited by the
13 sagging caused by thermal expansion of the conductors, which also occurs
14 more readily with summer peak conditions of high air temperatures, light
15 winds and strong sunlight. Overheating and sagging also reduce the operating
16 life of the conductors.

17 **Q: For the second category of costs, what usage factors indirectly increase
18 the costs of geographic expansion of the distribution system?**

19 A: AEP Ohio and its predecessor companies historically extended service to
20 connect customers based on the revenues that could be expected from the
21 additional connected load. Since the investor-owned utilities did not find it
22 economic to serve all areas of the state, rural households and businesses
23 organized cooperatives, which now serve a large fraction of Ohio, as
24 measured by the area of service territories.

25 AEP Ohio currently charges for “the cost of residential construction in
26 excess of five thousand dollars for single-family residences and twenty-five

1 hundred dollars per unit for multifamily residences”.²³ This provision
2 reflects the Company’s greater willingness to invest in system extensions for
3 large customers than for small customers.

4 **Q: With regard to the third category of costs, which costs tend to be**
5 **correlated with customer usage level but are not directly caused by**
6 **customer usage?**

7 A: Examples of this category would include bad debt, the costs associated with
8 adding line transformers to avoid long runs of secondary with high loads, or
9 the additional distribution costs between very large suburban homes, as
10 opposed to close-packed urban duplexes or apartments.

11 The higher the customer’s usage and bills, the more bad debt AEP Ohio
12 will incur if the customer leaves without paying the final month’s bill, or
13 declares bankruptcy owing money to AEP Ohio.

14 The length of secondary runs permissible from transformers to
15 customers depends on the load on the lines. Longer lines have higher voltage
16 drop, and voltage drop rises with load, so small customers can be further
17 from the transformer than can large customers. In order to serve a large load
18 at acceptable voltage, AEP Ohio must install a transformer close to the
19 customer’s service drop. A single transformer can serve many small
20 customers up and down the block, while large customers at the same
21 locations would require multiple transformers.

22

²³ Ohio Power Company P.U.C.O. No. 20, Terms and Conditions of Service, 2nd Revised Sheet No. 103-7, available at www.aepohio.com/global/utilities/lib/docs/ratesandtariffs/Ohio/2017-04-28_AEP_Ohio_Standard_Tariff.pdf.

1 **Q: How does the Company’s proposal to increase the residential customer**
2 **charge by \$2 per month affect the energy rate?**

3 A: Raising the customer charge by \$5 per month reduces the energy rate by
4 \$4.85/MWh, and raising it by \$10 (AEP Ohio’s proposed base customer
5 charge as of January 1, 2018) would reduce the energy rate by \$9.7/MWh, or
6 0.97¢/kWh.²⁴ Existing riders would add about 43.3% to this effect, bringing
7 the total reduction in the energy charge to 1.39¢/kWh. As a percentage of the
8 total basic residential energy rate, (about 12.1¢/kWh for the Ohio Power zone
9 and about 11.4¢/kWh for the Columbus Southern zone), this 1.39¢ reduction
10 would be about 11.5% for Ohio Power and 12.2% for Columbus Southern.²⁵

11 **VI. RATE DESIGN PRINCIPLES AND THE IMPACTS OF A HIGHER**
12 **CUSTOMER CHARGE**

13 **Q: Once cost-based customer and energy charges are calculated, what is the**
14 **next step in designing rates?**

15 A: The next step is to determine whether the customer charge and energy charge
16 estimates derived from the cost of service analysis adhere to the Bonbright
17 rate design principles, and whether they further the objectives of relevant
18 Ohio energy policy. I focus specifically below on the impacts of AEP Ohio’s
19 proposal in relation to Bonbright criteria Criteria 6 and 7 that require rates to
20 be designed “fairly” and to avoid “undue discrimination,” criterion 8 that

²⁴ Workpapers for Exhibit DRG-10.

²⁵ Calculation of based on current energy rates in the Bill Calculation Spreadsheets on AEP Ohio’s web site, available at www.aepohio.com/account/bills/rates/AEPOhioRatesTariffsOH.aspx.

1 focuses the rate design process on providing efficient price signals, and
2 Ohio's energy policy reflected in ORC §4928.02.

3 **Q: Please summarize the impacts of a higher residential customer charge on**
4 **AEP's customers.**

5 A: Even though the AEP Ohio proposal would not directly increase the
6 Company's aggregate revenues, and hence is revenue-neutral, it would
7 nonetheless significantly affect bills and the extent to which customers would
8 be motivated or rewarded for investing in clean energy options.

9 As discussed in Section VI.A below, the vast majority of residential
10 customers will pay more per month under AEP Ohio's proposal. Further, as
11 explained in Section VI.B, the increased electric consumption resulting from
12 the rate changes would offset years of energy efficiency investment and
13 customers would face longer payback periods when they make these
14 investments in the future. In order to maintain planned savings, AEP Ohio
15 might need to increase energy-efficiency program rebates recovered through
16 the Energy Efficiency and Peak Demand Reduction Cost Recovery Rider.
17 Because of these effects, all customers would eventually shoulder higher
18 costs for both the distribution investments required by higher load growth
19 and the higher energy-efficiency incentives. For these reasons, AEP Ohio's
20 proposal is inconsistent with long-standing ratemaking principles and Ohio
21 energy policy.

22
23

1 *A. Impacts on Customer Bills*

2 **Q: Has AEP Ohio provided comprehensive data showing the effect of its**
3 **customer-charge proposal on residential bills?**

4 A: No. In the testimony of witness David Gill, AEP Ohio presents bill effects
5 for only three levels of energy usage: 1,000, 2,000 and 4,000 kWh per
6 month.²⁶ He does not break these numbers down into smaller increments, or
7 provide a window into the bill impacts for customers using less than 1,000
8 kWh per month. Further, Mr. Gill's summary shows the effect of all rate
9 changes proposed in the Amended ESP, not just the increase in the customer
10 charge.

11 But Mr. Gill's testimony on even this limited cross-section of energy
12 users is misleading. Increasing the customer charge and decreasing the
13 energy charge in any tariff (while collecting the same revenue) would
14 increase the bills of low-use customers and reduce the bills of high-use
15 customers. The only customers who experience no change—i.e. those who
16 “break even”—are those using the average monthly energy. That break-even
17 point for the Company's proposed change in rate design is about 1,031 kWh
18 per month.²⁷ It is thus not surprising that Mr. Gill reported only a small
19 increase for customers with 1,000 kWh usage and bill reductions for the
20 higher consumption levels.

21 But this does not provide a representative or complete picture of the
22 effects of the customer-charge increase for the vast majority of AEP Ohio's
23 customers—most of whom use less than 1,000 kWh per month. As shown in

²⁶ Gill Direct at 12.

²⁷ Moore Direct at 13.

1 Table 2 below, 64.4% of the Company's residential customers use less than
2 1,000 kWh/month, 93.9% use less than 2,000 kWh, and over 99% use less
3 than 4,000 kWh.²⁸

4 **Q: Have you produced a more complete and representative bill analysis for**
5 **the proposed customer charge increase?**

6 A: Yes. In Table 2, I report the effect of the proposal on customer bills, for each
7 of the usage levels for which AEP Ohio provided data. The "Bill Change"
8 column shows the bill impacts for various usage levels in two ways: first, the
9 base rate impacts of the proposed \$10 per month customer-charge increase
10 and the 0.97¢/kWh energy-charge reduction; second, the impacts of both the
11 base rates and the 43.3% adders to base revenues, which would yield an
12 effective \$14.33/month increase in the customer charge, and a drop in the
13 energy charge by 1.39¢/kWh. This analysis excludes future expected changes
14 in the adders. As shown in Table 2, over 64% of customers would experience
15 an increase, about 40% would see an increase over \$5/month, and about 11%
16 would experience an increase of more than \$10/month.

²⁸ It remains unclear how many customers actually use more than 4,000 kWh monthly, since AEP Ohio grouped all bills over 3,000 kWh into the highest block of the data in response to discovery requests. See Exhibit PLC-6, which I used to construct Table 2. At the rate at which the number of bills fall as energy use increases (about 17% for every 100 kWh increase in usage), only about 0.3% of the customers would use over 4,000 kWh.

1

Table 2: Effect of Proposed Customer Charge on Bills

kWh/ month	Total Bills	% of Customers	Cumulative %	Bill Change	
				Base Rate	Total Bill
0	3,406	0.4%	0.4%	\$10.00	\$14.33
0-100	20,113	2.2%	2.6%	\$9.52	\$13.63
100-200	26,110	2.9%	5.5%	\$8.55	\$12.24
200-300	47,777	5.3%	10.7%	\$7.58	\$10.85
300-400	67,424	7.4%	18.1%	\$6.61	\$9.46
400-500	70,543	7.8%	25.9%	\$5.64	\$8.07
500-600	72,644	8.0%	33.9%	\$4.67	\$6.68
600-700	75,498	8.3%	42.2%	\$3.70	\$5.29
700-800	74,308	8.2%	50.4%	\$2.73	\$3.90
800-900	67,810	7.5%	57.8%	\$1.76	\$2.51
900-1,000	60,033	6.6%	64.4%	\$0.79	\$1.12
1,000-1,100	51,258	5.6%	70.1%	(\$0.19)	(\$0.27)
1,100-1,200	43,453	4.8%	74.8%	(\$1.16)	(\$1.66)
1,200-1,300	36,507	4.0%	78.9%	(\$2.13)	(\$3.05)
1,300-1,400	30,558	3.4%	82.2%	(\$3.10)	(\$4.44)
1,400-1,500	25,916	2.9%	85.1%	(\$4.07)	(\$5.83)
1,500-1,600	22,046	2.4%	87.5%	(\$5.04)	(\$7.22)
1,600-1,700	18,514	2.0%	89.5%	(\$6.01)	(\$8.61)
1,700-1,800	15,807	1.7%	91.3%	(\$6.98)	(\$10.00)
1,800-1,900	13,265	1.5%	92.7%	(\$7.95)	(\$11.39)
1,900-2,000	11,077	1.2%	93.9%	(\$8.92)	(\$12.78)
2,000-2,100	9,336	1.0%	95.0%	(\$9.89)	(\$14.17)
2,100-2,200	7,709	0.8%	95.8%	(\$10.86)	(\$15.56)
2,200-2,300	6,283	0.7%	96.5%	(\$11.83)	(\$16.95)
2,300-2,400	5,270	0.6%	97.1%	(\$12.80)	(\$18.34)
2,400-2,500	4,298	0.5%	97.6%	(\$13.77)	(\$19.73)
2,500-2,600	3,565	0.4%	98.0%	(\$14.74)	(\$21.12)
2,600-2,700	3,029	0.3%	98.3%	(\$15.71)	(\$22.51)
2,700-2,800	2,422	0.3%	98.6%	(\$16.68)	(\$23.90)
2,800-2,900	1,981	0.2%	98.8%	(\$17.65)	(\$25.29)
2,900-3,000	1,632	0.2%	99.0%	(\$18.62)	(\$26.68)
>3,000	9,529	1.0%	100.0%	(\$26.38)	(\$48.22)

Source: Ex. PLC-6

Bill effect is computed for middle of range

>3,000 is computed for 4,500 kWh

1 Further, AEP Ohio’s filings confirm that these increases compound over
 2 time. Table 3 reflects calculations derived from Mr. Gill’s electronic
 3 workpapers²⁹ demonstrating that, even with the other expected rider changes,
 4 customers using more than 1,000 kWh will see lower bills, while customers
 5 using 250 kWh would experience 12% increases by mid-2018, and 40% by
 6 2024, as shown in Table 3.³⁰

7 **Table 3: Percentage Total Bill Change From November 2016**

Level of Usage	November 2016 Total Bill	June 2018 Total Bill	2016-2018 Change	2024 Total Bill	2016-2024 Change
	<i>A</i>	<i>B</i>	$c = b \div a - 1$	<i>D</i>	$e = d \div a - 1$
0	\$12.91	\$29.71	130%	\$37.00	187%
50	\$19.35	\$35.24	82%	\$42.24	118%
150	\$32.23	\$46.32	44%	\$52.73	64%
250	\$45.11	\$57.39	27%	\$63.21	40%
350	\$57.99	\$68.47	18%	\$73.70	27%
450	\$70.87	\$79.54	12%	\$84.18	19%
550	\$83.75	\$90.62	8%	\$94.67	13%
800	\$115.95	\$118.30	2%	\$120.88	4%
1,000	\$141.71	\$140.45	-1%	\$141.85	0%
1,200	\$167.47	\$162.60	-3%	\$162.82	-3%
1,500	\$206.11	\$195.83	-5%	\$194.28	-6%
2,000	\$270.51	\$251.20	-7%	\$246.71	-9%

8

9 **Q: Do you have any other concerns with regard to these impacts on**
 10 **customer bills?**

11 A: Yes. The Company proposes a 119% increase in the customer charge for
 12 residential customers between now and January 1, 2018. As shown in Table

²⁹ The file “typical Bill impacts DRG-7.xlsx,” which are the workpapers for Exh. DRG-7.

³⁰ I changed the “level of usage” values in the electronic workpaper for Exh. DRG-7 (the Ohio Power SSO Impacts sheet) to the values shown in Table 3, copied columns *a*, *b*, *c* and *d*, and computed column *e*.

1 2, over 64% of customers would experience an increase, about 40% would
2 see an increase over \$5/month, and about 11% would experience an increase
3 of more than \$10/month. Despite Ms. Moore’s testimony that “the Company
4 is proposing to implement this charge in a gradual fashion”³¹ these cannot be
5 considered gradual changes, in contravention of longstanding ratemaking
6 principles.

7 ***B. Impacts on Energy Use and Energy Efficiency***

8 **Q: Please summarize the impacts of AEP Ohio’s proposal on energy**
9 **efficiency?**

10 A: The proposed rate design restructuring would send inefficient rate signals
11 that encourage customers to consume more energy, setting Ohio’s energy
12 efficiency efforts back years. In addition, customers would face longer
13 payback periods for energy-efficiency investments, likely reducing incentives
14 to participate in AEP Ohio’s new slate of energy efficiency programming.

15 **Q: To what extent would the lower energy rate under the Company’s**
16 **proposed customer charge dampen price signals for conservation?**

17 A: Residential customers respond to the price incentives created by the electrical
18 rate structure. Those responses are generally measured as price elasticities,
19 i.e., the ratio of the percentage change in consumption to the percentage
20 change in price. Price elasticities are generally low in the short term and rise
21 over several years, because customers have more options for increasing or
22 reducing energy usage in the medium to long term. For example, a review by
23 Espey and Espey (2004) of thirty-six articles on residential electricity

³¹ Moore Direct at 13.

1 demand published between 1971 and 2000 reports short-run average-rate
2 elasticity estimates of about -0.35 on average across studies and long-run
3 average-rate elasticity estimates of about -0.85 on average across studies.³²

4 Studies of electric price response typically examine the change in usage
5 as a function of changes in the marginal rate paid by the customer. Table 4
6 lists the results of seven studies of marginal-price elasticity over the last forty
7 years.³³

8 **Table 4: 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 non-electric heat -0.52 with space heat
Barnes, Gillingham, and Hageman	1981	-0.55
Henson	1984	-0.27 to -0.30
Reiss and White	2001	-0.39
Xcel Energy Colorado	2012	-0.3 (at years 2 and 3)
Li, Orans, Kahn-Lang, and Woo	2014	-0.13 in 3 rd year of phased-in rate

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

11 A: From Table 4, it appears that -0.3 would be a reasonable mid-range estimate
12 of the impact over a few years.

13
14

³² Available at <http://ageconsearch.tind.io/bitstream/42897/2/Espey%20JAAE%20April%202004.pdf>. In other words, on average across these studies, consumption decreased by 0.35% in the short term and by 0.85% in the long term for every 1% increase in average rates.

³³ These studies (or links thereto) are in Exhibit PLC-7.

1 **Q: What would be a reasonable estimate of the effect on energy use from**
2 **the reduction to the energy rate under the Company's proposal?**

3 A: An elasticity of -0.3 and the 11.5% reduction in energy price for Ohio Power
4 would result in an increase in energy consumption of about 3.7%; with the
5 12.3% reduction for the Columbus Southern zone, energy consumption
6 would be expected to rise 4%. This means that all else equal, residential load
7 would be expected to increase by almost 4% over the next few years as a
8 result of implementing the Company's proposed customer charge increase.³⁴

9 For comparison, the Company's 2018 and 2019 goals for energy
10 savings from its consumer sector programs with continuing savings amount
11 to a reduction of about 0.73% of residential sales annually.³⁵ The
12 consumption increase due to the Company's proposed increase to the
13 residential customer charge (and the resulting decrease in the energy charge)
14 would increase energy consumption enough to undo over five years of
15 residential energy-efficiency savings. Since AEP Ohio is spending about \$30
16 million annually on those programs, the increase in the customer charge
17 would offset about \$150 million of Company investment and some additional
18 participant investments. The Company projects a utility cost test ratio (the
19 ratio of avoided costs to utility spending) of about 3.0 for these programs, so

³⁴ Based on the change in the energy charge (0.97¢) plus the 43.3% adders (0.42¢), for a total of 1.39¢ .

³⁵ Case No. 16-0574-EL-POR, *AEP Ohio 2017 to 2019 Energy Efficiency/Peak Demand Reduction (EE/PDR) Action Plan*, Exhibit JFW-1, June 15, 2016, Table 4. (Included in Ex. PLC-15.) I excluded the costs and benefits of the two programs that AEP did not consider to accumulate benefits, Behavior Change and Intelligent Home & Demand Response, and scaled the percentage of sales proportionately. The effects of rate-design changes, like those of the other efficiency programs, would last many years. Limiting the analysis to programs with long-term savings makes the comparison to rate-design incentives easier and clearer.

1 the lost present-value savings would be about \$450 million. These data are
 2 summarized in Table 5.

3 **Table 5: Projected Residential Energy-Efficiency Program Savings,**
 4 **Utility Cost and Benefit-Cost Ratio**

Program	Incremental Annual Energy (GWh) Savings at Meter			Investments \$M			Utility Cost Test Ratio
	2017	2018	2019	2017	2018	2019	
Appliance Recycling	11.8	11.9	11.9	\$3.20	\$3.40	\$3.50	1.3
Community Assistance	8.4	8.5	8.5	\$8.50	\$8.50	\$8.50	0.8
e3smart	6.8	6.8	6.9	\$1.20	\$1.20	\$1.20	4
Efficient Products	64.5	61.1	57	\$9.10	\$8.70	\$8.00	5.5
In-Home Energy	8.7	8.3	8.6	\$5.30	\$5.10	\$5.20	1.8
New Home	4.7	4.8	6.1	\$2.40	\$2.40	\$3.10	1.7
Manufactured Home	2.2	2.5	2.5	\$0.70	\$0.80	\$0.80	2
Total	107.1	103.9	101.5	30.4	30.1	30.3	2.5

AEP Ohio 2017 to 2019 Energy Efficiency/Peak Demand Reduction (EE/PDR) Action Plan, June 15, 2016, Tables 4, 7 and 9. Exhibit PLC-15.

5 **Q: Is your use of an elasticity of -0.3 critical in determining that AEP**
 6 **Ohio’s proposal to increase the customer charge would impose large**
 7 **costs through increased consumption?**

8 A: No. Even if the demand elasticity were much smaller, the costs would be
 9 substantial.

10 **Q: Did the Company consider these impacts of the increased customer**
 11 **charged on energy conservation?**

12 A: No. It appears that AEP has not conducted this inquiry.³⁶ Without any
 13 analysis, AEP Ohio suggests that the roughly 12% reduction in the energy
 14 charge “will maintain the opportunity for plenty of savings for lowering

³⁶ See Ex. PLC-8. (the Company responded that it has not performed the requested analyses – “any studies or documents available to the Company that estimate the extent to which a decrease in energy charges will increase energy usage by customers”).

1 energy usage.”³⁷ Certainly, customers could still save money by reducing
2 usage, but those savings would be 12% smaller, weakening incentives to
3 invest in efficient equipment, use setback thermostats, or be careful about
4 using electricity.

5 **Q: Would the change in rate design have any other effect on customer**
6 **efficiency efforts?**

7 A: Yes. Reducing the energy rate by about 12% would increase the payback
8 period for investments in efficiency and alternative energy. A measure that
9 would have a 5-year payback under current rates would have a 5.6 year
10 payback period with the proposed rates.

11 Table 6 shows the effect of the reduction in energy costs on the payback
12 periods for some residential energy-efficiency measures, from AEP Ohio’s
13 2017–2019 Energy Efficiency/Peak Demand Reduction Action Plan. I
14 selected measures that AEP Ohio included in its programs and that have at
15 least a three-year payback period. Depending on the measure and the zone,
16 paybacks increase from little more than 3 years to nearly four years, from
17 under four years to about 4.5 years, and so on, up to under 10 years to over
18 11 years.³⁸

³⁷ Ex. PLC-9.

³⁸ The 1.4¢/kWh difference in the energy rate includes the base decrease in the energy charge, and the 43.3% of current riders.

Table 6: Payback for Selected Energy-Efficiency Measures

Efficiency Measure	Annual Energy	Incentive	Incremental Cost	Participant Cost	Energy Price			
					OP Zone		CSP Zone	
					\$0.121	\$0.107	\$0.114	\$0.100
					<i>now</i>	<i>prop</i>	<i>now</i>	<i>prop</i>
	<i>A</i>	<i>B</i>	<i>C</i>	<i>d</i>	<i>e</i>	<i>f</i>	<i>g</i>	<i>h</i>
VSD Pool Pump	1,170	\$200	\$750	\$550	3.9	4.4	4.1	4.7
Efficient Refrigerator (ENERGY STAR® or Better)	104	\$50	\$90	\$40	3.2	3.6	3.4	3.8
ENERGY STAR® Freezer	36	\$10	\$35	\$25	5.7	6.5	6.1	6.9
Clothes Washer - Tier 3 >= 2.2 MEF-w/gas or no dry	130	\$50	\$101	\$51	3.3	3.7	3.5	4.0
High Performance Circulating Pump (DHW)	354	\$50	\$300	\$250	5.8	6.6	6.2	7.1
Tier 2 GSHP, Closed Loop, water to air	653	\$500	\$1,203	\$703	8.9	10.1	9.4	10.8
Ductless Mini Split HP SEER 18	159	\$200	\$377	\$177	9.2	10.4	9.8	11.1
Duct Sealing and Insulation -Heat Pump	1,511	\$70	\$760	\$690	3.8	4.3	4.0	4.6
ENERGY STAR® Double Pane Windows -Central A/C -Non-EL Heat	126	\$50	\$150	\$100	6.6	7.4	7.0	7.9
Triple Pane Windows -Central A/C -Non-EL Heat	199	\$75	\$250	\$175	7.3	8.2	7.7	8.8
Drain Water Heat Recovery (42% efficient or higher)	391	\$250	\$660	\$410	8.7	9.8	9.2	10.5
ENERGY STAR® 3.0 Qualified Home - Heat Pump	3,389	\$1,000	\$2,329	\$1,329	3.2	3.7	3.4	3.9
Sources: Columns <i>a-c</i> : Exhibit PLC-16. Column <i>d</i> : $b - a$ Columns <i>e-h</i> : $d \div (a \times \text{energy price})$								

1 VII. OTHER CONCERNS WITH AEP OHIO'S PROPOSAL

2 A. *Bill Volatility*

3 **Q: Does you agree with Ms. Moore that the Company's proposal will**
4 **reduce bill volatility for some customers?**

5 A: A higher fixed charge does reduce changes from one monthly bill to the next.
6 But I disagree with the implication that increasing the customer charge would
7 be a reasonable way to address bill volatility. As detailed in the prior sections
8 of this testimony, the Company's proposal comes with high costs in
9 efficiency and in equity, as smaller customers would be charged for
10 equipment that is required only by the usage of larger customers.

11 **Q: Does AEP Ohio provide another mechanism for customers who prefer to**
12 **moderate volatility?**

13 A: Yes. The Company offers an Average Monthly Payment ("AMP") plan,
14 which it describes on its web site as follows:³⁹

15 The AMP plan significantly moderates the monthly bill variation while
16 avoiding the potential of accumulating a large settlement balance, or
17 credit, at the anniversary month. Please note that this is not an equal
18 monthly payment plan.

19 The monthly payment on the AMP Plan is based on the average of the
20 current month's bill, plus the previous 11 months' bills. Each month, the
21 oldest bill is removed from the computation, and the new current bill is
22 included. As a result, the payment amount will fluctuate slightly from
23 month to month.

³⁹ See <https://www.aepohio.com/account/bills/manage/LevelPayments.aspx>, at the "Learn more about our Average Monthly Payment Plan" link.

1 The difference between actual billings and the average billings will be
2 carried in a deferred balance that will accumulate both debit and credit
3 differences for the duration of the AMP Plan year (12 consecutive
4 months).

5 At the anniversary month, the deferred balance is divided by 12, and
6 this one-twelfth amount is added to (or subtracted from) the average
7 payment amount for the next 12 months.

8 This smoothing process would provide customers who want stable bills
9 a high level of stability, without reducing the rewards for conservation that
10 would accompany a customer charge increase.

11 **Q: Does revenue decoupling moderate the volatility of bills?**

12 A: Yes. If sales are high due to extreme weather in one year, revenue decoupling
13 (in the form of the Company's existing PTBAR) returns the excess revenues
14 to customers in the next year. While the AMP program tamps down
15 variability in a year, revenue decoupling smoothes out bills over multiple
16 years.

17 **B. PIPP and Low-Income Customers**

18 **Q: Has Ms. Moore demonstrated that the increased customer charge “will**
19 **lower the PIPP bills, therefore lowering the future revenue requirement**
20 **of the Universal Service Fund”?**⁴⁰

21 A: No. Ms. Moore's testimony notes that the average customer currently on the
22 PIPP program use slightly more than the class average, so the Universal
23 Service Fund charge would be marginally lower with a higher customer
24 charge. She did not address the issue of whether an additional charge that
25 may exceed \$150 annually will push into the PIPP some customers who are

⁴⁰ Moore Direct at 13.

1 either: 1) not eligible now, but would be with the additional charge; or 2) are
2 eligible now, but have not bothered to file for PIPP benefits, since their bills
3 are so small, but would do so if their bills rose several dollars a month. The
4 Company admitted that it has not done any analysis to determine whether the
5 higher proposed customer charge would push currently eligible but non-
6 participating customers into the PIPP plan.⁴¹

7 **Q: How would AEP Ohio’s proposed dramatic increase in the customer**
8 **charge affect low-income customers?**

9 A: The Company does not appear to know. It was unable to provide “any data
10 on the bill frequency distribution of the Company’s low-income residential
11 customers, other than those on the Percentage of Income Payment Plan” and
12 said that it “has not performed the requested analysis.”⁴²

13 This is a serious omission in AEP’s filing. Given the significant impacts
14 of the customer charge on monthly bills for those who use less than the
15 average amount of electricity, it is critical that the Company evaluate who
16 these customers are and the extent to which the impacts will
17 disproportionately burden low-income Ohioans, those on fixed incomes, and
18 other vulnerable customers. Without such foundational information, the
19 Company cannot have legitimately addressed the needs of these customers or
20 taken steps to address the regressive effects of its proposal.

41 Ex. PLC-10.

42 Ex. PLC-11.

1 **VIII. DECOUPLING SALES FROM REVENUE**

2 **Q: What action does AEP Ohio request regarding revenue decoupling?**

3 A: AEP Ohio witness Jon F. Williams requests that the Commission continue
4 the PTBAR for residential and small commercial customers (on the GS1 rate)
5 and expand the mechanism to include all commercial and industrial
6 customers.⁴³ The PTBAR decouples the distribution revenue received by
7 AEP Ohio from the energy consumption of its customers.

8 **Q: What is your recommendation with respect to these requests?**

9 A: I support those requests. The PTBAR trues up actual distribution revenue to
10 allowed revenue, reducing sales risk to both AEP Ohio and customers, while
11 removing the principle financial disincentive for AEP Ohio to support
12 customers in reducing their usage through energy efficiency (through utility-
13 sponsored programs or otherwise) and distributed energy resources, such as
14 solar and other distributed generation.

15 **Q: How does the PTBAR benefit customers?**

16 A: The PTBAR provides two types of customer benefit. First, it reduces the
17 volatility of electric bills with respect to weather. In a hot summer (and to
18 some extent, in a cold winter), customer bills are higher for distribution and
19 generation services, since customers will tend to use more kilowatt-hours.⁴⁴
20 Decoupling returns those excess revenues to customers.

21 Second, decoupling benefits customers by increasing the likelihood that
22 AEP Ohio will pursue and support options that reduce customers' costs, even

⁴³ Williams Direct at 24–25.

⁴⁴ Customers with demand meters are also likely to experience higher demand charges.

1 while also reducing the Company's sales. Initiatives in this category could
2 include:

- 3 • Utility energy-efficiency programs beyond mandated levels.
- 4 • Support for energy efficiency sponsored by other parties, such as
5 building codes and efficiency standards.
- 6 • Behind-the-meter distributed generation.
- 7 • More effective rate designs, such as moving distribution rates from large
8 non-residential customers away from demand charges and towards time-
9 of-use energy charges.

10 **Q: Are there any alternative regulatory approaches for delivering these**
11 **benefits as effectively as revenue decoupling?**

12 A: No. With a great deal of continuing attention to detail, the Commission could
13 develop a mechanism for recovery of lost revenue from utility energy-
14 efficiency programs and behind-the-meter distributed generation, but that
15 would not help facilitate the other initiatives or provide revenue stability.
16 Recovering more distribution revenues through customer charges would
17 protect the utility against loss of revenues, but would result in inequitable and
18 inefficient rate design, as I discuss above.

19 The general trend in recent years has been for regulators to move from
20 lost-revenue mechanisms to decoupling, and to reject proposals to
21 significantly increase customer charges, although there are always
22 exceptions.

1 **IX. CONCERNS WITH DEMAND CHARGES**

2 **Q: Do you agree with Ms. Moore’s recommendation that residential**
3 **distribution costs should ideally be collected in demand charges?**⁴⁵

4 **A:** No. There are several flaws in Ms. Moore’s statements regarding demand
5 charges, which I discuss below.

6 **Q: How does AEP Ohio describe the cause and appropriate recovery of**
7 **distribution costs that are not caused by the number of customers on the**
8 **system?**

9 **A:** Ms. Moore says that “Distribution costs are incurred by sizing the
10 distribution system to meet customer(s) peak kW demand usage. These costs
11 vary by peak demand requirements, not by kWh usage or by simply
12 connecting a customer to the system. These costs would ideally be collected
13 through a demand charge.”⁴⁶

14 I assume that, by “demand charge,” Ms. Moore means a charge in \$/kW
15 or \$/kVA for the customer’s maximum rate of consumption over any 30-
16 minute period in each month, regardless of when that event occurs.⁴⁷

17 **Q: Are demand charges a common component of residential rates?**

18 **A:** No. While demand charges for commercial and industrial customers are
19 common, regulated utilities that have demand charges for residential

⁴⁵ Moore Direct at 13.

⁴⁶ *Id.*

⁴⁷ Some of AEP Ohio’s demand rates include a ratchet provision, under which the billing demand each month is the greater of that month’s maximum demand or a specified fraction of a previous month’s maximum demand.

1 customers are extremely rare.⁴⁸ Even for the utilities that have installed
2 meters that can measure customer maximum demand, regulators have
3 generally preferred to use those meters to bill for energy (sometimes by time
4 of use), rather than imposing a confusing, inequitable and inefficient demand
5 charge.

6 **Q: Is Ms. Moore correct about the cause and recovery of distribution costs?**

7 A: Not entirely. Distribution costs are incurred in part by sizing the distribution
8 system to meet high loads (including annual peak loads) on each piece of
9 equipment, not the customers' individual maximum demands or the class
10 peak load. Ms. Moore suggests that those costs, driven by loads in the hours
11 in which the combined loads of several, hundreds, or thousands of customers
12 (both residential and other classes) would ideally be collected through a
13 demand charge that imposes costs on each customer when it hits its
14 maximum demand for the month, whether that is at 11 pm on a Sunday or 5
15 am on a Wednesday.

16 **Q: Has AEP Ohio provided any justification for Ms. Moore's position that**
17 **costs that are driven by the coincident loads of many customers "should**
18 **ideally be recovered through a non-coincident demand charge"?**

19 A: No. To clarify Ms. Moore's statement, Ex. PLC-12 part B asked:

⁴⁸ Many non-residential customers are served by a dedicated transformer or bank of transformers, and a very large non-residential customer may be the dominant load on at least part of the feeder that serves it. Recovering a portion of distribution revenues through demand charges may better reflect cost causation for these customers than for residential customers.

1 Please explain whether Witness Moore’s reference to “customer(s) peak
2 kW demand usage” means one of the following: (i) each customer’s
3 maximum monthly demand, whenever it occurs; (ii) each customer’s
4 maximum annual demand, whenever it occurs; (iii) the customers’
5 collective maximum demand on the particular piece of distribution
6 equipment; (iv) or something else.

7 Ms. Moore responded as follows, indicating that the AEP Ohio cost-of-
8 service study assumes that three different kinds of peaks contribute to the
9 costs of the distribution system:

10 The statement is a general statement representing that the cost of service
11 study in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR provides for the
12 peak demands in allocation of the distribution system. Some equipment
13 is based on the coincident peak of the system while others are a
14 combination of the non-coincident peak as well as the annual non-
15 coincident peak.

16 Ms. Moore later clarified that “‘Non-coincident peak’ was referring to
17 the class maximum demand and ‘annual non-coincident peak’ was referring
18 to the sum of the individual customer maximum demand.”⁴⁹ Thus, AEP
19 Ohio allocates some the distribution costs on the system coincident peak (the
20 estimated class loads at hours of the AEP Ohio maximum load for the year),
21 some part on the class coincident peak (at the hour that AEP Ohio estimates
22 the class reaches its maximum load) and some on the sum of customer
23 maximum demands, at many different hours during the year.

24 Ex. PLC-12, parts C and D, asked:

25 If Witness Moore’s reference to “customer(s) peak kW demand usage”
26 means each customer’s maximum demand, regardless of timing, please
27 explain how this measure of customer load determines the sizing of line
28 transformers, feeders and substations.

⁴⁹ Ex. PLC-13.

1 To the extent Witness Moore believes that a residential customer's
2 maximum demand, whenever it occurs, determines the cost of
3 distribution equipment, please explain how that would be the case for (i)
4 the substation, (ii) the feeder; and (iii) the line transformer.

5 Ms. Moore's response provided no explanation for her claim that
6 "These costs would ideally be collected through a demand charge," and
7 simply described AEP Ohio's allocation method, without even offering any
8 justification for the allocation method:

9 The secondary distribution system (secondary lines, secondary
10 components of line transformers) are allocated using 50% of the
11 customer's maximum demand and 50% of the annual customers
12 demand. The primary system (primary lines, primary components of the
13 line transformers) as well as substations are allocated based on the peak
14 load.⁵⁰

15 It does not appear that AEP Ohio's allocation method is actually related
16 to the factors that cause distribution costs, which include high and maximum
17 loads in a variety of hours. If that method were cost-based, it would indicate
18 that a majority of the distribution costs (100% of the substations and primary
19 system, plus 50% of the secondary system) are driven by group peaks, not
20 the individual customers' undiversified maximum demands.

21 **Q: As a more general matter, would a demand charge be an appropriate**
22 **method for recovering distribution costs?**

23 A: No. A demand charge, as that term is generally used in utility practice,
24 imposes a charge based on the customer's highest usage (usually over 15
25 minutes or one hour) at any time during the month (and in some cases, any
26 time during the year). Demand charges are difficult to avoid and are therefore
27 often grouped with customer charges in the category of "fixed charges,"

⁵⁰ The "peak load" here is contribution to 6 coincident peaks (Ex. PLC-14).

1 while energy charges are considered to be variable and subject to customer
2 control.

3 Some utilities confuse ratemaking terminology, and assume that any
4 cost classified as “demand-related” in an embedded cost-of-service study
5 should be recovered through a demand charge, imposed on customers in
6 proportion to their individual non-coincident maximum demand. In reality,
7 demand-related costs are related to coincident peaks or other high loads on
8 various transmission and distribution equipment, and are typically allocated
9 on measures of coincident demands or proxies, such as class diversified peak
10 loads.

11 A similar confusion arises in the conflation of two meanings of “fixed
12 costs:”

13 Fixed Costs 1: costs invariant with respect to load or usage, and thus
14 not avoidable by reducing load.

15 Fixed Costs 2: costs fixed over the year, not varying in the short run.

16 Many costs in any particular year are largely determined by the
17 cumulative investment and construction commitments in the past, and are
18 hence fixed by Definition 2. However, even though distribution costs are
19 overwhelmingly fixed over the year, none of them are fixed over load, since
20 plant is added to maintain reliability and reduce losses as load grows. Hence,
21 they are not fixed by Definition 1 and should be recovered through rates that
22 vary with usage and encourage customers to reduce and control the usage
23 that contributes to the costs.

24 **Q: Are demand charges helpful in providing price signals to ratepayers?**

25 A: No. Demand charges are inappropriate for several reasons, including the
26 following:

- 1 • Demand charges do not target peak demand reduction, since they apply
2 to customer maximum demands, not to the times of system peaks or
3 equipment maximum loads. Customer peaks occur at a wide variety of
4 hours, on a wide variety of days, with many far from the coincident
5 peaks on the distribution equipment.
- 6 • Demand charges do not provide appropriate incentives to conserve,
7 even during the system's high-load hours.
- 8 • Not only are demand charges ineffective in shifting loads off high-cost
9 hours, they may cause some customers to shift loads in ways that
10 increase costs. For a customer who experiences its maximum summer
11 demands at noon or 9 pm, a demand charge encourages the shifting of
12 load into the afternoon peaks on the generation, transmission and
13 distribution systems.
- 14 • Demand charges are very difficult for customers to understand, let alone
15 mitigate. It is difficult to find an example of a product for which
16 consumers pay based on their maximum usage rate.

17 **Q: Please explain why demand charges do not provide the appropriate**
18 **incentives.**

19 A: Demand charges are a particularly ineffective means for giving price signals,
20 for the following reasons:

- 21 • The demand-charge portion of the electric bill is determined by the
22 customer's individual maximum demand. Capacity costs are driven by
23 coincident loads at the times of the peak loads on each piece of
24 equipment (substation, feeder, transformer), not by the non-coincident
25 maximum demands of individual customers. The customer's individual

1 peak hour is not likely to coincide with the peak hours of the other
2 customers sharing a piece of equipment, especially since the peaks on
3 the secondary system, line transformer, primary tap, feeder, substations,
4 and sub-transmission lines occur at varying times.

- 5 • Demand charges provide little or no incentive to control or shift load
6 from those times that are off the customers' peak hours but that are very
7 much on the system peak hours. Customers can avoid demand charges
8 merely by redistributing load within the peak period. Some of those
9 customers will be shifting loads from their own peak to the peak hour
10 on the local distribution system. This will cause customers to increase
11 their contribution to maximum or critical loads on the local distribution
12 system, the transmission system, and/or the regional generation system.
- 13 • Demand charges are difficult to avoid; even a single failure to control
14 load results in the same demand charge as if the same demand had been
15 reached in every day or every hour. This attribute of demand charges
16 erodes the incentive to even try to avoid the charge, since weeks of
17 careful effort can be swept away if the electric water heater and
18 refrigerator happen to go on simultaneously. Once a customer is aware
19 of having hit a high billing demand for the month, the demand charge
20 offers no reward for controlling load any time that the customer's load
21 is less than that prior demand.
- 22 • Rather than promoting conservation at high-cost times, or shifting of
23 load from system peak periods, demand charges encourage customers to
24 waste resources on the arbitrary tasks of flattening their personal
25 maximum loads, even if those occur at low-cost times. For instance, in

1 order to respond to demand charges effectively, customers will need to
2 install equipment to monitor loads, interrupt discretionary load, and
3 schedule deferrable loads. Moreover, lower energy charges will
4 encourage increased electric use, some of which will likely occur in the
5 peak period.

6 **Q: Does AEP Ohio have any residential tariff that uses a measure of**
7 **demand?**

8 A: Yes. Schedule RDMS (Residential Demand Metered Service) charges a
9 lower energy price for energy used in excess of 400 hours times a monthly
10 billing demand defined as “the number of kilowatts determined by
11 dividing the number of kilowatt-hours used during the on-peak period in
12 the month by the number of hours in such period.”⁵¹

13 This is essentially a time-of-use rate that assumes that monthly energy
14 consumption above 400 times the average load in the peak period would be
15 less expensive to serve. Any energy used in the peak period would increase
16 the threshold at which the rate falls to the lower price. The rate requires that
17 AEP Ohio measure usage in the peak period, and it could be replaced by a
18 simple time-of-use rate. Interestingly, this rate demonstrates a more useful
19 approach to defining the customer load that imposes higher cost on the
20 distribution system. By recognizing that usage any time in the peak period
21 may result in heavy loads and heat buildup in various parts of the distribution
22 system, including the customer’s transformer, the feeder, the distribution

⁵¹ Ohio Power Company P.U.C.O. No. 20, Terms and Conditions of Service, 6th Revised Sheet No. 213-1, available at www.aepohio.com/global/utilities/lib/docs/ratesandtariffs/Ohio/2017-04-28_AEP_Ohio_Standard_Tariff.pdf.

1 substation, (and potentially one or more higher-voltage distribution lines and
2 substations).

3 **Q: Ms. Moore proposes an opt-in demand charge for residential**
4 **customers.⁵² Is there any merit to this proposal?**

5 A: No. The demand charge does not distinguish between a customer with a
6 maximum demand of, for example, 7 kW at 11 pm once a month and an
7 average of 3 kW on the high-load hours for the distribution equipment, or 7
8 kW every day in the distribution high load from 10 am to 9 pm and an
9 average of 5 kW the rest of the month. The second customer puts much more
10 stress on the system but pays no more for doing so. As I explained above, the
11 demand charge may just encourage customers to shift load off their own peak
12 hours (which may occur at 6 am or midnight) onto the peak hours of various
13 distribution equipment.

14 It is my understanding that AEP Ohio has deployed meters with
15 extensive billing capability, which should be used to charge customers for
16 usage at the times that cause costs, through time-of-use or other time-varying
17 rates, rather than to implement a 19th century rate design, developed when
18 time-of-use was not feasible. Even as an optional test, AEP Ohio should be
19 concentrating its efforts on more efficient rate designs.

20 **X. RECOMMENDATIONS**

21 **Q: Please summarize your recommendations in this proceeding.**

22 A: I recommend that the Commission:

- 23 • Reject the Company's proposal to increase the customer charge and
24 decrease the energy charge.

⁵² Moore Direct at 14.

- 1 • Approve the Company’s request to extend and broaden the PTBAR
2 mechanism.

3 **Q: Do you have any recommendations regarding subsequent proceedings?**

4 A: Yes. It is my understanding that the Commission is currently undertaking an
5 initiative called PowerForward, focused on reviewing and modernizing
6 Ohio’s infrastructure and processes. AEP Ohio’s rate design proposal could
7 very likely limit options in that initiative for optimizing the grid and
8 providing the best outcomes for consumers. Thus, I recommend that, in
9 addition to rejecting AEP Ohio’s proposal, the Commission consider
10 exploring alternative rate designs as part of PowerForward that can move
11 Ohio toward more efficient options, such as reducing customer and demand
12 charges and recovering more revenue through time-varying rates supported
13 by AEP Ohio’s advanced metering. As part of that process, the Commission
14 could consider in future cases the revision of some riders, so that rate
15 increases will fall more on energy charges and less on customer and demand
16 charges.

17 In addition, before any further rate proposals are made, I recommend
18 that the Commission require that AEP Ohio (or any other utility, for that
19 matter) collect information on the frequency of low-income customers by
20 usage level, not limited to PIPP participants. In addition, the Company
21 should insure that its load-research program includes enough low-income
22 customers to allow for statistically reliable estimates of the load shapes of
23 that group. Such information will allow the Commission to avoid
24 inadvertently burdening low-income customers in the rate design process,
25 including potential future introduction of time-varying rates.

1 **Q: Does this conclude your direct testimony?**

2 A: Yes.

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing *Direct Testimony of Paul L. Chernick* submitted on behalf of Natural Resource Defense Council was served by electronic mail upon the following Parties of Record on May 2, 2017.

/s/ Robert Dove
Robert Dove

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SUMMARY OF PROFESSIONAL EXPERIENCE

- 1986–Present* **President, Resource Insight, Inc.** Consults and testifies in utility and insurance economics. Reviews utility supply-planning processes and outcomes: assesses prudence of prior power planning investment decisions, identifies excess generating capacity, analyzes effects of power-pool-pricing rules on equity and utility incentives. Reviews electric-utility rate design. Estimates magnitude and cost of future load growth. Designs and evaluates conservation programs for electric, natural-gas, and water utilities, including hook-up charges and conservation cost recovery mechanisms. Determines avoided costs due to cogenerators. Evaluates cogeneration rate risk. Negotiates cogeneration contracts. Reviews management and pricing of district heating systems. Determines fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects. Determines profitability of transportation services. Advises regulatory commissions in least-cost planning, rate design, and cost allocation.
- 1981–86* **Research Associate, Analysis and Inference, Inc.** (Consultant, 1980–81). Researched, advised, and testified in various aspects of utility and insurance regulation. Designed self-insurance pool for nuclear decommissioning; estimated probability and cost of insurable events, and rate levels; assessed alternative rate designs. Projected nuclear power plant construction, operation, and decommissioning costs. Assessed reasonableness of earlier estimates of nuclear power plant construction schedules and costs. Reviewed prudence of utility construction decisions. Consulted on utility rate-design issues, including small-power-producer rates; retail natural-gas rates; public-agency electric rates, and comprehensive electric-rate design for a regional power agency. Developed electricity cost allocations between customer classes. Reviewed district-heating-system efficiency. Proposed power-plant performance standards. Analyzed auto-insurance profit requirements. Designed utility-financed, decentralized conservation program. Analyzed cost-effectiveness of transmission lines.
- 1977–81* **Utility Rate Analyst, Massachusetts Attorney General.** Analyzed utility filings and prepared alternative proposals. Participated in rate negotiations, discovery, cross-examination, and briefing. Provided extensive expert testimony before various regulatory agencies. Topics included demand forecasting, rate design, marginal costs, time-of-use rates, reliability issues, power-pool operations, nuclear-power cost projections, power-plant cost-benefit analysis, energy conservation, and alternative-energy development.

EDUCATION

SM, Technology and Policy Program, Massachusetts Institute of Technology, February 1978.

SB, Civil Engineering Department, Massachusetts Institute of Technology, June 1974.

HONORS

Chi Epsilon (Civil Engineering)

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Institute Award, Institute of Public Utilities, 1981.

PUBLICATIONS

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PRESENTATIONS

“Rethinking Utility Rate Design—Retail Demand and Energy Charges,” Solar Power PV Conference, Boston MA, February 24, 2016.

“Residential Demand Charges - Load Effects, Fairness & Rate Design Implications.” Web seminar sponsored by the NixTheFix Forum. September 2015.

“The Value of Demand Reduction Induced Price Effects.” With Chris Neme. Web seminar sponsored by the Regulatory Assistance Project. March 2015.

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Reliability, capacity planning, capability responsibility allocation, customer generation, co-generation rates, reserve margins, operating reserve allocation. Joint testimony with S. Finger.

6. **U.S. ASLB NRC 50-471**, Pilgrim Unit 2; Commonwealth of Massachusetts. June 29 1979.

Review of the Oak Ridge National Laboratory and NEPOOL demand forecast models; cost-effectiveness of oil displacement; nuclear economics. Joint testimony with Susan Geller.

7. **Mass. DPU 19845**, Boston Edison time-of-use-rate case; Massachusetts Attorney General. December 4 1979. (Not presented)

Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with Susan Geller.

8. **Mass. DPU 20055**, petition of Eastern Utilities Associates, New Bedford G. & E., and Fitchburg G. & E. to purchase additional shares of Seabrook Nuclear Plant; Massachusetts Attorney General. January 23 1980.

Review of demand forecasts of three utilities purchasing Seabrook shares; Seabrook power costs, including construction cost, completion date, capacity factor, O&M expenses, interim replacements, reserves and uncertainties; alternative energy sources, including conservation, cogeneration, rate reform, solar, wood and coal conversion.

9. **Mass. DPU 20248**, petition of Massachusetts Municipal Wholesale Electric Company to purchase additional share of Seabrook Nuclear Plant; Massachusetts Attorney General. June 2 1980.

Nuclear power costs; update and extension of MDPU 20055 testimony.

10. **Mass. DPU 200**, Massachusetts Electric Company rate case; Massachusetts Attorney General. June 16 1980.

Rate design; declining blocks, promotional rates, alternative energy, demand charges, demand ratchets; conservation: master metering, storage heating, efficiency standards, restricting resistance heating.

11. **Mass. EFSC 79-33**, Eastern Utilities Associates 1979 forecast; Massachusetts Attorney General. July 16 1980.

Customer projections, consistency issues, appliance efficiency, new appliance types, commercial specifications, industrial data manipulation and trending, sales and resale.

- 12. Mass. DPU 243**, Eastern Edison Company rate case; Massachusetts Attorney General. August 19 1980.

Rate design: declining blocks, promotional rates, alternative energy, master metering.

- 13. Texas PUC 3298**, Gulf States Utilities rate case; East Texas Legal Services. August 25 1980.

Inter-class revenue allocations, including production plant in-service, O&M, CWP, nuclear fuel in progress, amortization of canceled plant residential rate design; interruptible rates; off-peak rates. Joint testimony with M. B. Meyer.

- 14. Mass. EFSC 79-1**, Massachusetts Municipal Wholesale Electric Company Forecast; Massachusetts Attorney General. November 5 1980.

Cost comparison methodology; nuclear cost estimates; cost of conservation, cogeneration, and solar.

- 15. Mass. DPU 472**, recovery of residential conservation-service expenses; Massachusetts Attorney General. December 12 1980.

Conservation as an energy source; advantages of per-kWh allocation over per-customer-month allocation.

- 16. Mass. DPU 535**; regulations to carry out Section 210 of PURPA; Massachusetts Attorney General. January 26 1981 and February 13 1981.

Filing requirements, certification, qualifying-facility status, extent of coverage, review of contracts; energy rates; capacity rates; extra benefits of qualifying facilities in specific areas; wheeling; standardization of fees and charges.

- 17. Mass. EFSC 80-17**, Northeast Utilities 1980 forecast; Massachusetts Attorney General. March 12 1981 (not presented).

Specification process, employment, electric heating promotion and penetration, commercial sales model, industrial model specification, documentation of price forecasts and wholesale forecast.

- 18. Mass. DPU 558**, Western Massachusetts Electric Company rate case; Massachusetts Attorney General. May 1981.

Rate design including declining blocks, marginal cost conservation impacts, and promotional rates. Conservation, including terms and conditions limiting renewable, cogeneration, small power production; scope of current conservation program; efficient insulation levels; additional conservation opportunities.

19. **Mass. DPU 1048**, Boston Edison plant performance standards; Massachusetts Attorney General. May 7 1982.
 Critique of company approach, data, and statistical analysis; description of comparative and absolute approaches to standard-setting; proposals for standards and reporting requirements.
20. **D.C. psc FC785**, Potomac Electric Power rate case; D.C. People's Counsel. July 29 1982.
 Inter-class revenue allocations, including generation, transmission, and distribution plant classification; fuel and O&M classification; distribution and service allocators. Marginal cost estimation, including losses.
21. **N.H. psc DE 81-312**, Public Service of New Hampshire supply and demand; Conservation Law Foundation et al. October 8 1982.
 Conservation program design, ratemaking, and effectiveness. Cost of power from Seabrook nuclear plant, including construction cost and duration, capacity factor, O&M, replacements, insurance, and decommissioning.
22. **Mass. Division of Insurance**, hearing to fix and establish 1983 automobile insurance rates; Massachusetts Attorney General. October 1982.
 Profit margin calculations, including methodology, interest rates, surplus flow, tax flows, tax rates, and risk premium.
23. **Ill. cc 82-0026**, Commonwealth Edison rate case; Illinois Attorney General. October 15 1982.
 Review of Cost-Benefit Analysis for nuclear plant. Nuclear cost parameters (construction cost, O&M, capital additions, useful life, capacity factor), risks, discount rates, evaluation techniques.
24. **N.M. psc 1794**, Public Service of New Mexico application for certification; New Mexico Attorney General. May 10 1983.
 Review of Cost-Benefit Analysis for transmission line. Review of electricity price forecast, nuclear capacity factors, load forecast. Critique of company ratemaking proposals; development of alternative ratemaking proposal.
25. **Conn. DPUC 830301**, United Illuminating rate case; Connecticut Consumers Counsel. June 17 1983.
 Cost of Seabrook nuclear power plants, including construction cost and duration, capacity factor, O&M, capital additions, insurance and decommissioning.
26. **Mass. DPU 1509**, Boston Edison plant performance standards; Massachusetts Attorney General. July 15 1983.

Critique of company approach and statistical analysis; regression model of nuclear capacity factor; proposals for standards and for standard-setting methodologies.

27. **Mass. Division of Insurance**, hearing to fix and establish 1984 automobile-insurance rates; Massachusetts Attorney General. October 1983.

Profit margin calculations, including methodology, interest rates.

28. **Conn. DPUC 83-07-15**, Connecticut Light and Power rate case; Alloy Foundry. October 3 1983.

Industrial rate design. Marginal and embedded costs; classification of generation, transmission, and distribution expenses; demand versus energy charges.

29. **Mass. EFSC 83-24**, New England Electric System forecast of electric resources and requirements; Massachusetts Attorney General. November 14 1983, Rebuttal, February 2 1984.

Need for transmission line. Status of supply plan, especially Seabrook 2. Review of interconnection requirements. Analysis of cost-effectiveness for power transfer, line losses, generation assumptions.

30. **Mich. PSC U-7775**, Detroit Edison Fuel Cost Recovery Plan; Public Interest Research Group in Michigan. February 21 1984.

Review of proposed performance target for new nuclear power plant. Formulation of alternative proposals.

31. **Mass. DPU 84-25**, Western Massachusetts Electric Company rate case; Massachusetts Attorney General. April 6 1984.

Need for Millstone 3. Cost of completing and operating unit, cost-effectiveness compared to alternatives, and its effect on rates. Equity and incentive problems created by CWP. Design of Millstone 3 phase-in proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

32. **Mass. DPU 84-49 and 84-50**, Fitchburg Gas & Electric financing case; Massachusetts Attorney General. April 13 1984.

Cost of completing and operating Seabrook nuclear units. Probability of completing Seabrook 2. Recommendations regarding FG&E and MDPU actions with respect to Seabrook.

33. **Mich. PSC U-7785**, Consumers Power fuel-cost-recovery plan; Public Interest Research Group in Michigan. April 16 1984.

Review of proposed performance targets for two existing and two new nuclear power plants. Formulation of alternative policy.

34. **FERC ER81-749-000 and ER82-325-000**, Montaup Electric rate cases; Massachusetts Attorney General. April 27 1984.

Prudence of Montaup and Boston Edison in decisions regarding Pilgrim 2 construction: Montaup's decision to participate, the Utilities' failure to review their earlier analyses and assumptions, Montaup's failure to question Edison's decisions, and the utilities' delay in canceling the unit.

- 35. Maine PUC 84-113**, Seabrook-1 investigation; Maine Public Advocate. September 13 1984.

Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate effects. Recommendations regarding utility and PUC actions with respect to Seabrook.

- 36. Mass. DPU 84-145**, Fitchburg Gas and Electric rate case; Massachusetts Attorney General. November 6 1984.

Prudence of Fitchburg and Public Service of New Hampshire in decision regarding Seabrook 2 construction: FGE's decision to participate, the utilities' failure to review their earlier analyses and assumptions, FGE's failure to question PSNH's decisions, and utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

- 37. Penn. PUC R-842651**, Pennsylvania Power and Light rate case; Pennsylvania Consumer Advocate. November 1984.

Need for Susquehanna 2. Cost of operating unit, power output, cost-effectiveness compared to alternatives, and its effect on rates. Design of phase-in and excess capacity proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

- 38. N.H. PSC 84-200**, Seabrook Unit-1 investigation; New Hampshire Consumer Advocate. November 15 1984.

Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate and financial effects.

- 39. Mass. Division of Insurance**, hearing to fix and establish 1986 automobile insurance rates; Massachusetts Attorney General. November 1984.

Profit-margin calculations, including methodology and implementation.

- 40. Mass. DPU 84-152**, Seabrook Unit 1 investigation; Massachusetts Attorney General. December 12 1984.

Cost of completing and operating Seabrook. Probability of completing Seabrook 1. Seabrook capacity factors.

- 41. Maine PUC 84-120;** Central Maine Power rate case; Maine PUC Staff. December 11 1984.

Prudence of Central Maine Power and Boston Edison in decisions regarding Pilgrim 2 construction: CMP's decision to participate, the utilities' failure to review their earlier analyses and assumptions, CMP's failure to question Edison's decisions, and the utilities' delay in canceling the unit. Prudence of CMP in the planning and investment in Sears Island nuclear and coal plants. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

- 42. Maine PUC 84-113,** Seabrook 2 investigation; Maine PUC Staff. December 14 1984.

Prudence of Maine utilities and Public Service of New Hampshire in decisions regarding Seabrook 2 construction: decisions to participate and to increase ownership share, the utilities' failure to review their earlier analyses and assumptions, failure to question PSNH's decisions, and the utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

- 43. Mass. DPU 1627,** Massachusetts Municipal Wholesale Electric Company financing case; Massachusetts Executive Office of Energy Resources. January 14 1985.

Cost of completing and operating Seabrook nuclear unit 1. Cost of conservation and other alternatives to completing Seabrook. Comparison of Seabrook to alternatives.

- 44. Vt. PSB 4936,** Millstone 3 costs and in-service date; Vermont Department of Public Service. January 21 1985.

Construction schedule and cost of completing Millstone Unit 3.

- 45. Mass. DPU 84-276,** rules governing rates for utility purchases of power from qualifying facilities; Massachusetts Attorney General. March 25 1985 and October 18 1985.

Institutional and technological advantages of Qualifying Facilities. Potential for QF development. Goals of QF rate design. Parity with other power sources. Security requirements. Projecting avoided costs. Capacity credits. Pricing options. Line loss corrections.

- 46. Mass. DPU 85-121,** investigation of the Reading Municipal Light Department; Wilmington (Mass.) Chamber of Commerce. November 12 1985.

Calculation on return on investment for municipal utility. Treatment of depreciation and debt for ratemaking. Geographical discrimination in street-lighting rates. Relative size of voluntary payments to Reading and other towns. Surplus and disinvestment. Revenue allocation.

47. **Mass. Division of Insurance**, hearing to fix and establish 1986 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. November 1985.

Profit margin calculations, including methodology, implementation, modeling of investment balances, income, and return to shareholders.

48. **N.M. PSC 1833, Phase II**; El Paso Electric rate case; New Mexico Attorney General. December 23 1985.

Nuclear decommissioning fund design. Internal and external funds; risk and return; fund accumulation, recommendations. Interim performance standard for Palo Verde nuclear plant.

49. **Penn. PUC R-850152**, Philadelphia Electric rate case; Utility Users Committee and University of Pennsylvania. January 14 1986.

Limerick-1 rate effects. Capacity benefits, fuel savings, operating costs, capacity factors, and net benefits to ratepayers. Design of phase-in proposals.

50. **Mass. DPU 85-270**; Western Massachusetts Electric rate case; Massachusetts Attorney General. March 19 1986.

Prudence of Northeast Utilities in generation planning related to Millstone 3 construction: decisions to start and continue construction, failure to reduce ownership share, failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

51. **Penn. PUC R-850290**, Philadelphia Electric auxiliary service rates; Albert Einstein Medical Center, University of Pennsylvania, and Amtrak. March 24 1986.

Review of utility proposals for supplementary and backup rates for small power producers and cogenerators. Load diversity, cost of peaking capacity, value of generation, price signals, and incentives. Formulation of alternative supplementary rate.

52. **N.M. PSC 2004**, Public Service of New Mexico Palo Verde issues; New Mexico Attorney General. May 7 1986.

Recommendations for power-plant performance standards for Palo Verde nuclear units 1, 2, and 3.

53. **Ill. CC 86-0325**, Iowa-Illinois Gas and Electric Co. rate investigation; Illinois Office of Public Counsel. August 13 1986.

Determination of excess capacity based on reliability and economic concerns. Identification of specific units associated with excess capacity. Required reserve margins.

54. **N.M. PSC 2009**, El Paso Electric rate moderation program; New Mexico Attorney General. August 18 1986. (Not presented).

Prudence of EPE in generation planning related to Palo Verde nuclear construction, including failure to reduce ownership share and failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

Recommendation for rate-base treatment; proposal of power plant performance standards.

55. **City of Boston Public Improvements Commission**, transfer of Boston Edison district heating steam system to Boston Thermal Corporation; Boston Housing Authority. December 18 1986.

History and economics of steam system; possible motives of Boston Edison in seeking sale; problems facing Boston Thermal; information and assurances required prior to Commission approval of transfer.

56. **Mass. Division of Insurance**, hearing to fix and establish 1987 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. December 1986 and January 1987.

Profit margin calculations, including methodology, implementation, derivation of cash flows, installment income, income tax status, and return to shareholders.

57. **Mass. DPU 87-19**, petition for adjudication of development facilitation program; Hull (Mass.) Municipal Light Plant. January 21 1987.

Estimation of potential load growth; cost of generation, transmission, and distribution additions. Determination of hook-up charges. Development of residential load estimation procedure reflecting appliance ownership, dwelling size.

58. **N.M. PSC 2004**, Public Service of New Mexico nuclear decommissioning fund; New Mexico Attorney General. February 19 1987.

Decommissioning cost and likely operating life of nuclear plants. Review of utility funding proposal. Development of alternative proposal. Ratemaking treatment.

59. **Mass. DPU 86-280**, Western Massachusetts Electric rate case; Massachusetts Energy Office. March 9 1987.

Marginal cost rate design issues. Superiority of long-run marginal cost over short-run marginal cost as basis for rate design. Relationship of Consumer reaction, utility planning process, and regulatory structure to rate design approach. Implementation of short-run and long-run rate designs. Demand versus energy charges, economic development rates, spot pricing.

- 60. Mass. Division of Insurance 87-9**, 1987 Workers' Compensation rate filing; State Rating Bureau. May 1987.
- Profit-margin calculations, including methodology, implementation, surplus requirements, investment income, and effects of 1986 Tax Reform Act.
- 61. Texas PUC 6184**, economic viability of South Texas Nuclear Plant #2; Committee for Consumer Rate Relief. August 17 1987.
- Nuclear plant operating parameter projections; capacity factor, O&M, capital additions, decommissioning, useful life. STNP-2 cost and schedule projections. Potential for conservation.
- 62. Minn. PUC ER-015/GR-87-223**, Minnesota Power rate case; Minnesota Department of Public Service. August 17 1987.
- Excess capacity on MP system; historical, current, and projected. Review of MP planning prudence prior to and during excess; efforts to sell capacity. Cost of excess capacity. Recommendations for ratemaking treatment.
- 63. Mass. Division of Insurance 87-27**, 1988 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. September 2 1987. Rebuttal October 8 1987.
- Underwriting profit margins. Effect of 1986 Tax Reform Act. Biases in calculation of average margins.
- 64. Mass. DPU 88-19**, power Sales Contract from Riverside Steam and Electric to Western Massachusetts Electric; Riverside Steam and Electric. November 4 1987.
- Comparison of risk from QF contract and utility avoided-cost sources. Risk of oil dependence. Discounting cash flows to reflect risk.
- 65. Mass. Division of Insurance 87-53**, 1987 Workers' Compensation rate refiling; State Rating Bureau. December 14 1987.
- Profit-margin calculations including updating of data, compliance with Commissioner's order, treatment of surplus and risk, interest rate calculation, and investment tax rate calculation.
- 66. Mass. Division of Insurance**, 1987 and 1988 automobile insurance remand rates; Massachusetts Attorney General and State Rating Bureau. February 5 1988.
- Underwriting profit margins. Provisions for income taxes on finance charges. Relationships between allowed and achieved margins, between statewide and nationwide data, and between profit allowances and cost projections.

67. **Mass. DPU 86-36**, investigation into the pricing and ratemaking treatment to be afforded new electric generating facilities which are not qualifying facilities; Conservation Law Foundation. May 2 1988.

Cost recovery for utility conservation programs. Compensating for lost revenues. Utility incentive structures.

68. **Mass. DPU 88-123**, petition of Riverside Steam & Electric Company; Riverside Steam and Electric Company. May 18 1988 and November 8 1988.

Estimation of avoided costs of Western Massachusetts Electric Company. Nuclear capacity factor projections and effects on avoided costs. Avoided cost of energy interchange and power plant life extensions. Differences between median and expected oil prices. Salvage value of cogeneration facility. Off-system energy purchase projections. Reconciliation of avoided cost projection.

69. **Mass. DPU 88-67**, Boston Gas Company; Boston Housing Authority. June 17 1988.

Estimation of annual avoidable costs, 1988 to 2005, and levelized avoided costs. Determination of cost recovery and carrying costs for conservation investments. Standards for assessing conservation cost-effectiveness. Evaluation of cost-effectiveness of utility funding of proposed natural gas conservation measures.

70. **R.I. PUC 1900**, Providence Water Supply Board tariff filing; Conservation Law Foundation, Audubon Society of Rhode Island, and League of Women Voters of Rhode Island. June 24 1988.

Estimation of avoidable water supply costs. Determination of costs of water conservation. Conservation cost-benefit analysis.

71. **Mass. Division of Insurance 88-22**, 1989 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau; Profit Issues, August 12 1988, supplemented August 19 1988; Losses and Expenses, September 16 1988.

Underwriting profit margins. Effects of 1986 Tax Reform Act. Taxation of common stocks. Lag in tax payments. Modeling risk and return over time. Treatment of finance charges. Comparison of projected and achieved investment returns.

72. **Vt. PSB 5270 Module 6**, investigation into least-cost investments, energy efficiency, conservation, and the management of demand for energy; Conservation Law Foundation, Vermont Natural Resources Council, and Vermont Public Interest Research Group. September 26 1988.

Cost recovery for utility conservation programs. Compensation of utilities for revenue losses and timing differences. Incentive for utility participation.

73. **Vt. House of Representatives, Natural Resources Committee**, House Act 130; “Economic Analysis of Vermont Yankee Retirement”; Vermont Public Interest Research Group. February 21 1989.
- Projection of capacity factors, operating and maintenance expense, capital additions, overhead, replacement power costs, and net costs of Vermont Yankee.
74. **Mass. DPU 88-67 Phase II**, Boston Gas company conservation program and rate design; Boston Gas Company. March 6 1989.
- Estimation of avoided gas cost; treatment of non-price factors; estimation of externalities; identification of cost-effective conservation.
75. **Vt. PSB 5270**, status conference on conservation and load management policy settlement; Central Vermont Public Service, Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group, and Vermont Department of Public Service. May 1 1989.
- Cost-benefit test for utility conservation programs. Role of externalities. Cost recovery concepts and mechanisms. Resource allocations, cost allocations, and equity considerations. Guidelines for conservation preapproval mechanisms. Incentive mechanisms and recovery of lost revenues.
76. **Boston Housing Authority Court 05099**, Gallivan Boulevard Task Force vs. Boston Housing Authority, et al.; Boston Housing Authority. June 16 1989.
- Effect of master-metering on consumption of natural gas and electricity. Legislative and regulatory mandates regarding conservation.
77. **Mass. DPU 89-100**, Boston Edison rate case; Massachusetts Energy Office. June 30 1989.
- Prudence of BECo’s decision to spend \$400 million from 1986–88 on returning the Pilgrim nuclear power plant to service. Projections of nuclear capacity factors, O&M, capital additions, and overhead. Review of decommissioning cost, tax effect of abandonment, replacement power cost, and plant useful life estimates. Requirements for prudence and used-and-useful analyses.
78. **Mass. DPU 88-123**, petition of Riverside Steam and Electric Company; Riverside Steam and Electric. July 24 1989. Rebuttal, October 3 1989.
- Reasonableness of Northeast Utilities’ 1987 avoided cost estimates. Projections of nuclear capacity factors, economy purchases, and power plant operating life. Treatment of avoidable energy and capacity costs and of off-system sales. Expected versus reference fuel prices.

79. **Mass. DPU 89-72**, Statewide Towing Association police-ordered towing rates; Massachusetts Automobile Rating Bureau. September 13 1989.

Review of study supporting proposed increase in towing rates. Critique of study sample and methodology. Comparison to competitive rates. Supply of towing services. Effects of joint products and joint sales on profitability of police-ordered towing. Joint testimony with I. Goodman.

80. **Vt. PSB 5330**, application of Vermont utilities for approval of a firm power and energy contract with Hydro-Quebec; Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group. December 19 1989. Surrebuttal February 6 1990.

Analysis of a proposed 450-MW, 20-year purchase of Hydro-Quebec power by twenty-four Vermont utilities. Comparison to efficiency investment in Vermont, including potential for efficiency savings. Analysis of Vermont electric energy supply. Identification of possible improvements to proposed contract.

Critique of conservation potential analysis. Planning risk of large supply additions. Valuation of environmental externalities.

81. **Mass. DPU 89-239**, inclusion of externalities in energy-supply planning, acquisition, and dispatch for Massachusetts utilities. December 1989; April 1990; May 1990.

Critique of Division of Energy Resources report on externalities. Methodology for evaluating external costs. Proposed values for environmental and economic externalities of fuel supply and use.

82. **California PUC**, incorporation of environmental externalities in utility planning and pricing; Coalition of Energy Efficient and Renewable Technologies. February 21 1990.

Approaches for valuing externalities for inclusion in setting power purchase rates. Effect of uncertainty on assessing externality values.

83. **Ill. CC 90-0038**, proceeding to adopt a least-cost electric-energy plan for Commonwealth Edison Company; City of Chicago. May 25 1990. Joint rebuttal testimony with David Birr, August 14 1990.

Problems in Commonwealth Edison's approach to demand-side management. Potential for cost-effective conservation. Valuing externalities in least-cost planning.

84. **Md. PSC 8278**, adequacy of Baltimore Gas & Electric's integrated resource plan; Maryland Office of People's Counsel. September 18 1990.

Rationale for demand-side management. BG&E's problems in approach to DSM planning. Potential for cost-effective conservation. Valuation of environmental externalities. Recommendations for short-term DSM program priorities.

- 85. Ind. URC**, integrated-resource-planning docket; Indiana Office of Utility Consumer Counselor. November 1 1990.

Integrated resource planning process and methodology, including externalities and screening tools. Incentives, screening, and evaluation of demand-side management. Potential of resource bidding in Indiana.

- 86. Mass. DPU 89-141, 90-73, 90-141, 90-194, 90-270**; preliminary review of utility treatment of environmental externalities in October qualifying-facilities filings; Boston Gas Company. November 5 1990.

Generic and specific problems in Massachusetts utilities' RFPs with regard to externality valuation requirements. Recommendations for corrections.

- 87. Mass. EFSC 90-12/90-12A**, adequacy of Boston Edison proposal to build combined-cycle plant; Conservation Law Foundation. December 14 1990.

Problems in Boston Edison's treatment of demand-side management, supply option analysis, and resource planning. Recommendations of mitigation options.

- 88. Maine PUC 90-286**, adequacy of conservation program of Bangor Hydro Electric; Penobscot River Coalition. February 19 1991.

Role of utility-sponsored DSM in least-cost planning. Bangor Hydro's potential for cost-effective conservation. Problems with Bangor Hydro's assumptions about customer investment in energy efficiency measures.

- 89. Va. SCC PUE900070**, Order establishing commission investigation; Southern Environmental Law Center. March 6 1991.

Role of utilities in promoting energy efficiency. Least-cost planning objectives of and resource acquisition guidelines for DSM. Ratemaking considerations for DSM investments.

- 90. Mass. DPU 90-261-A**, economics and role of fuel-switching in the DSM program of the Massachusetts Electric Company; Boston Gas Company. April 17 1991.

Role of fuel-switching in utility DSM programs and specifically in Massachusetts Electric's. Establishing comparable avoided costs and comparison of electric and gas system costs. Updated externality values.

- 91. Private arbitration**, Massachusetts Refusetech Contractual Request for Adjustment to Service Fee; Massachusetts Refusetech. May 13 1991.

NEPCO rates for power purchases from the New England Solid Waste Compact plant. Fuel price and avoided cost projections vs. realities.

92. **Vt. PSB 5491**, cost-effectiveness of Central Vermont's commitment to Hydro Quebec purchases; Conservation Law Foundation. July 19 1991.

Changes in load forecasts and resale markets since approval of HQ purchases. Effect of HQ purchase on DSM.

93. **S.C. PSC 91-216-E**, cost recovery of Duke Power's DSM expenditures; South Carolina Department of Consumer Affairs. Direct, September 13 1991; Surrebuttal October 2 1991.

Problems with conservation plans of Duke Power, including load building, cream skimming, and inappropriate rate designs.

94. **Md. PSC 8241 Phase II**, review of Baltimore Gas & Electric's avoided costs; Maryland Office of People's Counsel. September 19 1991.

Development of direct avoided costs for DSM. Problems with BG&E's avoided costs and DSM screening. Incorporation of environmental externalities.

95. **Bucksport (Maine) Planning Board**, AES/Harriman Cove shoreland zoning application; Conservation Law Foundation and Natural Resources Council of Maine. October 1 1991.

New England's power surplus. Costs of bringing AES/Harriman Cove on line to back out existing generation. Alternatives to AES.

96. **Mass. DPU 91-131**, update of externalities values adopted in Docket 89-239; Boston Gas Company. October 4 1991. Rebuttal, December 13 1991.

Updates on pollutant externality values. Addition of values for chlorofluorocarbons, air toxics, thermal pollution, and oil import premium. Review of state regulatory actions regarding externalities.

97. **Fla. PSC 910759**, petition of Florida Power Corporation for determination of need for proposed electrical power plant and related facilities; Floridians for Responsible Utility Growth. October 21 1991.

Florida Power's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

98. **Fla. PSC 910833-EI**, petition of Tampa Electric Company for a determination of need for proposed electrical power plant and related facilities; Floridians for Responsible Utility Growth. October 31 1991.

Tampa Electric's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

- 99. Penn. PUC I-900005, R-901880;** investigation into demand-side management by electric utilities; Pennsylvania Energy Office. January 10 1992.
- Appropriate cost recovery mechanism for Pennsylvania utilities. Purpose and scope of direct cost recovery, lost revenue recovery, and incentives.
- 100. S.C. PSC 91-606-E,** petition of South Carolina Electric and Gas for a certificate of public convenience and necessity for a coal-fired plant; South Carolina Department of Consumer Affairs. January 20 1992.
- Justification of plant certification under integrated resource planning. Failures in SCE&G's DSM planning and company potential for demand-side savings.
- 101. Mass. DPU 92-92,** adequacy of Boston Edison's street-lighting options; Town of Lexington. June 22 1992.
- Efficiency and quality of street-lighting options. Boston Edison's treatment of high-quality street lighting. Corrected rate proposal for the Daylux lamp. Ownership of public street lighting.
- 102. S.C. PSC 92-208-E,** integrated-resource plan of Duke Power Company; South Carolina Department of Consumer Affairs. August 4 1992.
- Problems with Duke Power's DSM screening process, estimation of avoided cost, DSM program design, and integration of demand-side and supply-side planning.
- 103. N.C. UC E-100 Sub 64,** integrated-resource-planning docket; Southern Environmental Law Center. September 29 1992.
- General principles of integrated resource planning, DSM screening, and program design. Review of the IRPS of Duke Power Company, Carolina Power & Light Company, and North Carolina Power.
- 104. Ont. EAB Ontario Hydro Demand/Supply Plan Hearings, *Environmental Externalities Valuation and Ontario Hydro's Resource Planning* (3 vols.);** Coalition of Environmental Groups. October 1992.
- Valuation of environmental externalities from fossil fuel combustion and the nuclear fuel cycle. Application to Ontario Hydro's supply and demand planning.
- 105. Texas PUC 110000,** application of Houston Lighting and Power company for a certificate of convenience and necessity for the DuPont Project; Destec Energy, Inc. September 28 1992.
- Valuation of environmental externalities from fossil fuel combustion and the application to the evaluation of proposed cogeneration facility.

- 106. Maine BEP**, in the matter of the Basin Mills Hydroelectric Project application; Conservation Intervenors. November 16 1992.
- Economic and environmental effects of generation by proposed hydro-electric project.
- 107. Md. PSC 8473**, review of the power sales agreement of Baltimore Gas and Electric with AES Northside; Maryland Office of People's Counsel. November 16 1992.
- Non-price scoring and unquantified benefits; DSM potential as alternative; environmental costs; cost and benefit estimates.
- 108. N.C. UC E-100 Sub 64**, analysis and investigation of least cost integrated resource planning in North Carolina; Southern Environmental Law Center. November 18 1992.
- Demand-side management cost recovery and incentive mechanisms.
- 109. S.C. PSC 92-209-E**, in re Carolina Power & Light Company; South Carolina Department of Consumer Affairs. November 24 1992.
- Demand-side-management planning: objectives, process, cost-effectiveness test, comprehensiveness, lost opportunities. Deficiencies in CP&L's portfolio. Need for economic evaluation of load building.
- 110 Fla. DER** hearings on the Power Plant Siting Act; Legal Environmental Assistance Foundation. December 1992.
- Externality valuation and application in power-plant siting. DSM potential, cost-benefit test, and program designs.
- 111. Md. PSC 8487**, Baltimore Gas and Electric Company electric rate case. Direct, January 13 1993; rebuttal, February 4 1993.
- Class allocation of production plant and O&M; transmission, distribution, and general plant; administrative and general expenses. Marginal cost and rate design.
- 112. Md. PSC 8179**, Approval of amendment no. 2 to Potomac Edison purchase agreement with AES Warrior Run; Maryland Office of People's Counsel. January 29 1993.
- Economic analysis of proposed coal-fired cogeneration facility.
- 113. Mich. PSC U-10102**, Detroit Edison rate case; Michigan United Conservation Clubs. February 17 1993.
- Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

- 114. Ohio PUC** 91-635-EL-FOR, 92-312-EL-FOR, 92-1172-EL-ECP; Cincinnati Gas and Electric demand-management programs; City of Cincinnati. April 1993.
- Demand-side-management planning, program designs, potential savings, and avoided costs.
- 115. Mich. PSC** U-10335, Consumers Power rate case; Michigan United Conservation Clubs. October 1993.
- Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.
- 116. Ill. CC** 92-0268, electric-energy plan for Commonwealth Edison; City of Chicago. Direct, February 1 1994; rebuttal, September 1994.
- Cost-effectiveness screening of demand-side management programs and measures; estimates by Commonwealth Edison of costs avoided by DSM and of future cost, capacity, and performance of supply resources.
- 117. FERC** 2422 et al., application of James River–New Hampshire Electric, Public Service of New Hampshire, for licensing of hydro power; Conservation Law Foundation; 1993.
- Cost-effective energy conservation available to the Public Service of New Hampshire; power-supply options; affidavit.
- 118. Vt. PSB** 5270-CV-1,-3, and 5686; Central Vermont Public Service fuel-switching and DSM program design, on behalf of the Vermont Department of Public Service. Direct, April 1994; rebuttal, June 1994.
- Avoided costs and screening of controlled water-heating measures; risk, rate impacts, participant costs, externalities, space- and water-heating load, benefit-cost tests.
- 119. Fla. PSC** 930548-EG–930551-EG, conservation goals for Florida electric utilities; Legal Environmental Assistance Foundation, Inc. April 1994.
- Integrated resource planning, avoided costs, rate impacts, analysis of conservation goals of Florida electric utilities.
- 120. Vt. PSB** 5724, Central Vermont Public Service Corporation rate request; Vermont Department of Public Service. Joint surrebuttal testimony with John Plunkett. August 1994.
- Costs avoided by DSM programs; Costs and benefits of deferring DSM programs.
- 121. Mass. DPU** 94-49, Boston Edison integrated-resource-management plan; Massachusetts Attorney General. August 1994.
- Least-cost planning, modeling, and treatment of risk.

- 122. Mich. psc U-10554**, Consumers Power Company DSM program and incentive; Michigan Conservation Clubs. November 1994.

Critique of proposed reductions in DSM programs; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

- 123. Mich. psc U-10702**, Detroit Edison Company cost recovery, on behalf of the Residential Ratepayers Consortium. December 1994.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

- 124. N.J. BRC EM92030359**, environmental costs of proposed cogeneration; Freehold Cogeneration Associates. November 1994.

Comparison of potential externalities from the Freehold cogeneration project with that from three coal technologies; support for the study “The Externalities of Four Power Plants.”

- 125. Mich. psc U-10671**, Detroit Edison Company DSM programs; Michigan United Conservation Clubs. January 1995.

Critique of proposal to scale back DSM efforts in light of potential for competition. Loss of savings, increase of customer costs, and decrease of competitiveness. Discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

- 126. Mich. psc U-10710**, power-supply-cost-recovery plan of Consumers Power Company; Residential Ratepayers Consortium. January 1995.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

- 127. FERC 2458 and 2572**, Bowater–Great Northern Paper hydropower licensing; Conservation Law Foundation. February 1995.

Comments on draft environmental impact statement relating to new licenses for two hydropower projects in Maine. Applicant has not adequately considered how energy conservation can replace energy lost due to habitat-protection or -enhancement measures.

- 128. N.C. uc E-100 Sub 74**, Duke Power and Carolina Power & Light avoided costs; Hydro-Electric–Power Producer’s Group. February 1995.

Critique and proposed revision of avoided costs offered to small hydro-power producers by Duke Power and Carolina Power and Light.

- 129. New Orleans City Council** UD-92-2A and -2B, least-cost IRP for New Orleans Public Service and Louisiana Power & Light; Alliance for Affordable Energy. Direct, February 1995; rebuttal, April 1995.
Critique of proposal to scale back DSM efforts in light of potential competition.
- 130. D.C. psc** FC917 II, prudence of DSM expenditures of Potomac Electric Power Company; Potomac Electric Power Company. Rebuttal testimony, February 1995.
Prudence of utility DSM investment; prudence standards for DSM programs of the Potomac Electric Power Company.
- 131. Ont. Energy Board** EBRO 490, DSM cost recovery and lost-revenue–adjustment mechanism for Consumers Gas Company; Green Energy Coalition. April 1995.
Demand-side-management cost recovery. Lost-revenue–adjustment mechanism for Consumers Gas Company.
- 132. New Orleans City Council** CD-85-1, New Orleans Public Service rate increase; Alliance for Affordable Energy. Rebuttal, May 1995.
Allocation of costs and benefits to rate classes.
- 133. Mass. DPU** Docket DPU-95-40, Mass. Electric cost-allocation; Massachusetts Attorney General. June 1995.
Allocation of costs to rate classes. Critique of cost-of-service study. Implications for industry restructuring.
- 134. Md. psc** 8697, Baltimore Gas & Electric gas rate increase; Maryland Office of People’s Counsel. July 1995.
Rate design, cost-of-service study, and revenue allocation.
- 135. N.C. uc** E-2 Sub 669. December 1995.
Need for new capacity. Energy-conservation potential and model programs.
- 136. Arizona cc** U-1933-95-317, Tucson Electric Power rate increase; Residential Utility Consumer Office. January 1996.
Review of proposed rate settlement. Used-and-usefulness of plant. Rate design. DSM potential.
- 137. Ohio puc** 95-203-EL-FOR; Campaign for an Energy-Efficient Ohio. February 1996
Long-term forecast of Cincinnati Gas and Electric Company, especially its DSM portfolio. Opportunities for further cost-effective DSM savings. Tests of cost effectiveness. Role of DSM in light of industry restructuring; alternatives to traditional utility DSM.

- 138. Vt. PSB 5835**, Central Vermont Public Service Company rates; Vermont Department of Public Service. February 1996.
- Design of load-management rates of Central Vermont Public Service Company.
- 139. Md. PSC 8720**, Washington Gas Light DSM; Maryland Office of People's Counsel. May 1996.
- Avoided costs of Washington Gas Light Company; integrated least-cost planning.
- 140. Mass. DPU 96-100**, Massachusetts Utilities' Stranded Costs; Massachusetts Attorney General. Oral testimony in support of "estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities," July 1996.
- Stranded costs. Calculation of loss or gain. Valuation of utility assets.
- 141. Mass. DPU 96-70**, Essex County Gas Company rates; Massachusetts Attorney General. July 1996.
- Market-based allocation of gas-supply costs of Essex County Gas Company.
- 142. Mass. DPU 96-60**, Fall River Gas Company rates; Massachusetts Attorney General. Direct, July 1996; surrebuttal, August 1996.
- Market-based allocation of gas-supply costs of Fall River Gas Company.
- 143. Md. PSC 8725**, Maryland electric-utilities merger; Maryland Office of People's Counsel. July 1996.
- Proposed merger of Baltimore Gas & Electric Company, Potomac Electric Power Company, and Constellation Energy. Cost allocation of merger benefits and rate reductions.
- 144. N.H. PUC DR 96-150**, Public Service Company of New Hampshire stranded costs; New Hampshire Office of Consumer Advocate. December 1996.
- Market price of capacity and energy; value of generation plant; restructuring gain and stranded investment; legal status of PSNH acquisition premium; interim stranded-cost charges.
- 145. Ont. Energy Board EBRO 495**, LRAM and shared-savings incentive for DSM performance of Consumers Gas; Green Energy Coalition. March 1997.
- LRAM and shared-savings incentive mechanisms in rates for the Consumers Gas Company Ltd.
- 146. New York PSC 96-E-0897**, Consolidated Edison restructuring plan; City of New York. April 1997.
- Electric-utility competition and restructuring; critique of proposed settlement of Consolidated Edison Company; stranded costs; market power; rates; market access.

- 147. Vt. PSB 5980**, proposed statewide energy plan; Vermont Department of Public Service. Direct, August 1997; rebuttal, December 1997.
Justification for and estimation of statewide avoided costs; guidelines for distributed IRP.
- 148. Mass. DPU 96-23**, Boston Edison restructuring settlement; Utility Workers Union of America. September 1997.
Performance incentives proposed for the Boston Edison company.
- 149. Vt. PSB 5983**, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, October 1997; rebuttal, December 1997.
In three separate pieces of prefiled testimony, addressed the Green Mountain Power Corporation's (1) distributed-utility-planning efforts, (2) avoided costs, and (3) prudence of decisions relating to a power purchase from Hydro-Quebec.
- 150. Mass. DPU 97-63**, Boston Edison proposed reorganization; Utility Workers Union of America. October 1997.
Increased costs and risks to ratepayers and shareholders from proposed reorganization; risks of diversification; diversion of capital from regulated to unregulated affiliates; reduction in Commission authority.
- 151. Mass. DTE 97-111**, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Jonathan Wallach, January 1998.
Critique of proposed restructuring plan filed to satisfy requirements of the electric-utility restructuring act of 1997. Failure of the plan to foster competition and promote the public interest.
- 152. N.H. PUC Docket DR 97-241**, Connecticut Valley Electric fuel and purchased-power adjustments; City of Claremont, N.H. February 1998.
Prudence of continued power purchase from affiliate; market cost of power; prudence disallowances and cost-of-service ratemaking.
- 153. Md. PSC 8774**, APS-DQE merger; Maryland Office of People's Counsel. February 1998.
Proposed power-supply arrangements between APS's potential operating subsidiaries; power-supply savings; market power.
- 154. Vt. PSB 6018**, Central Vermont Public Service Co. rate increase; Vermont Department of Public Service. February 1998.
Prudence of decisions relating to a power purchase from Hydro-Quebec. Reasonableness of avoided-cost estimates. Quality of DU planning.

- 155. Maine PUC 97-580**, Central Maine Power restructuring and rates; Maine Office of Public Advocate. May 1998; Surrebuttal, August 1998.
- Determination of stranded costs; gains from sales of fossil, hydro, and biomass plant; treatment of deferred taxes; incentives for stranded-cost mitigation; rate design.
- 156. Mass. DTE 98-89**, purchase of Boston Edison municipal street lighting; Towns of Lexington and Acton. Affidavit, August 1998.
- Valuation of municipal streetlighting; depreciation; applicability of unbundled rate.
- 157. Vt. PSB 6107**, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, September 1998; Surrebuttal drafted but not filed, November 2000.
- Prudence of decisions relating to a power purchase from Hydro-Quebec. Least-cost planning and prudence. Quality of DU planning.
- 158. Mass. DTE 97-120**, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Jonathan Wallach, October 1998. Joint surrebuttal with Jonathan Wallach, January 1999.
- Market value of the three Millstone nuclear units under varying assumptions of plant performance and market prices. Independent forecast of wholesale market prices. Value of Pilgrim and TMI-1 asset sales.
- 159. Md. PSC 8794 and 8804**, BG&E restructuring and rates; Maryland Office of People's Counsel. Direct, December 1998; rebuttal, March 1999.
- Implementation of restructuring. Valuation of generation assets from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.
- 160. Md. PSC 8795**; Delmarva Power & Light restructuring and rates; Maryland Office of People's Counsel. December 1998.
- Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.
- 161. Md. PSC 8797**, Potomac Edison Company restructuring and rates; Maryland Office of People's Counsel. Direct, January 1999; rebuttal, March 1999.
- Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.
- 162. Conn. DPUC 99-02-05**, Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.
- Projections of market price. Valuation of purchase agreements and nuclear and non-nuclear assets from comparable-sales and cash-flow analyses.

- 163. Conn. DPUC 99-03-04**, United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear assets from comparable-sales and cash-flow analyses.

- 164. Wash. UTC UE-981627**, PacifiCorp–Scottish Power merger, Office of the Attorney General. June 1999.

Review of proposed performance standards and valuation of performance. Review of proposed low-income assistance.

- 165. Utah PSC 98-2035-04**, PacifiCorp–Scottish Power merger, Utah Committee of Consumer Services. June 1999.

Review of proposed performance standards and valuation of performance.

- 166. Conn. DPUC 99-03-35**, United Illuminating Company proposed standard offer; Connecticut Office of Consumer Counsel. July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost

- 167. Conn. DPUC 99-03-36**, Connecticut Light and Power Company proposed standard offer; Connecticut Office of Consumer Counsel. Direct, July 1999; supplemental, July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost.

- 168. W. Va. PSC 98-0452-E-GI**, electric-industry restructuring, West Virginia Consumer Advocate. July 1999.

Market value of generating assets of, and restructuring gain for, Potomac Edison, Monongahela Power, and Appalachian Power. Comparable-sales and cash-flow analyses.

- 169. Ont. Energy Board RP-1999-0034**, Ontario performance-based rates; Green Energy Coalition. September 1999.

Rate design. Recovery of demand-side-management costs under PBR. Incremental costs.

- 170. Conn. DPUC 99-08-01**, standards for utility restructuring; Connecticut Office of Consumer Counsel. Direct, November 1999; supplemental, January 2000.

Appropriate role of regulation. T&D reliability and service quality. Performance standards and customer guarantees. Assessing generation adequacy in a competitive market.

- 171. Conn. Superior Court CV 99-049-7239**, Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. Affidavit, December 1999.
- Errors of the Conn. DPUC in deriving discounted-cash-flow valuations for Millstone and Seabrook, and in setting minimum bid price.
- 172. Conn. Superior Court CV 99-049-7597**, United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. December 1999.
- Errors of the Conn. DPUC, in its discounted-cash-flow computations, in selecting performance assumptions for Seabrook, and in setting minimum bid price.
- 173. Ont. Energy Board RP-1999-0044**, Ontario Hydro transmission-cost allocation and rate design; Green Energy Coalition. January 2000.
- Cost allocation and rate design. Net vs. gross load billing. Export and wheeling-through transactions. Environmental implications of utility proposals.
- 174. Utah psc 99-2035-03**, PacifiCorp Sale of Centralia plant, mine, and related facilities; Utah Committee of Consumer Services. January 2000.
- Prudence of sale and management of auction. Benefits to ratepayers. Allocation and rate treatment of gain.
- 175. Conn. DPUC 99-09-12**, Nuclear Divestiture by Connecticut Light & Power and United Illuminating; Connecticut Office of Consumer Counsel. January 2000.
- Market for nuclear assets. Optimal structure of auctions. Value of minority rights. Timing of divestiture.
- 176. Ont. Energy Board RP-1999-0017**, Union Gas PBR proposal; Green Energy Coalition. March 2000.
- Lost-revenue-adjustment and shared-savings incentive mechanisms for Union Gas DSM programs. Standards for review of targets and achievements, computation of lost revenues. Need for DSM expenditure true-up mechanism.
- 177. N.Y. psc 99-S-1621**, Consolidated Edison steam rates; City of New York. April 2000.
- Allocation of costs of former cogeneration plants, and of net proceeds of asset sale. Economic justification for steam-supply plans. Depreciation rates. Weather normalization and other rate adjustments.
- 178. Maine puc 99-666**, Central Maine Power alternative rate plan; Maine Public Advocate. Direct, May 2000; Surrebuttal, August 2000.
- Likely merger savings. Savings and rate reductions from recent mergers. Implications for rates.

- 179. Mass. EFSB 97-4**, Massachusetts Municipal Wholesale Electric Company gas-pipeline proposal; Town of Wilbraham, Mass. June 2000.
Economic justification for natural-gas pipeline. Role and jurisdiction of EFSB.
- 180. Conn. DPUC 99-09-03**; Connecticut Natural Gas Corporation merger and rate plan; Connecticut office of Consumer Counsel. September 2000.
Performance-based ratemaking in light of mergers. Allocation of savings from merger. Earnings-sharing mechanism.
- 181. Conn. DPUC 99-09-12RE01**, Proposed Millstone sale; Connecticut Office of Consumer Counsel. November 2000.
Requirements for review of auction of generation assets. Allocation of proceeds between units.
- 182. Mass. DTE 01-25**, Purchase of streetlights from Commonwealth Electric; Cape Light Compact. January 2001
Municipal purchase of streetlights; Calculation of purchase price under state law; Determination of accumulated depreciation by asset.
- 183. Conn. DPUC 00-12-01 and 99-09-12RE03**, Connecticut Light & Power rate design and standard offer; Connecticut Office of Consumer Counsel. March 2001.
Rate design and standard offer under restructuring law; Future rate impacts; Transition to restructured regime; Comparison of Connecticut and California restructuring challenges.
- 184. Vt. PSB 6460 & 6120**, Central Vermont Public Service rates; Vermont Department of Public Service. Direct, March 2001; Surrebuttal, April 2001.
Review of decision in early 1990s to commit to long-term uneconomic purchase from Hydro Québec. Calculation of present damages from imprudence.
- 185. N.J. BPU EM00020106**, Atlantic City Electric Company sale of fossil plants; New Jersey Ratepayer Advocate. Affidavit, May 2001.
Comparison of power-supply contracts. Comparison of plant costs to replacement power cost. Allocation of sales proceeds between subsidiaries.
- 186. N.J. BPU GM00080564**, Public Service Electric and Gas transfer of gas supply contracts; New Jersey Ratepayer Advocate. Direct, May 2001.
Transfer of gas transportation contracts to unregulated affiliate. Potential for market power in wholesale gas supply and electric generation. Importance of reliable gas supply. Valuation of contracts. Effect of proposed requirements contract on rates. Regulation and design of standard-offer service.

- 187. Conn. DPUC** 99-04-18 Phase 3, 99-09-03 Phase 2; Southern Connecticut Natural Gas and Connecticut Natural Gas rates and charges; Connecticut Office of Consumer Counsel. Direct, June 2001; supplemental, July 2001.
- Identifying, quantifying, and allocating merger-related gas-supply savings between ratepayers and shareholders. Establishing baselines. Allocations between affiliates. Unaccounted-for gas.
- 188. N.J. BPU** EX01050303, New Jersey electric companies' procurement of basic supply; New Jersey Ratepayer Advocate. August 2001.
- Review of proposed statewide auction for purchase of power requirements. Market power. Risks to ratepayers of proposed auction.
- 189. N.Y. PSC** 00-E-1208, Consolidated Edison rates; City of New York. October 2001.
- Geographic allocation of stranded costs. Locational and postage-stamp rates. Causation of stranded costs. Relationship between market prices for power and stranded costs.
- 190. Mass. DTE** 01-56, Berkshire Gas Company; Massachusetts Attorney General. October 2001.
- Allocation of gas costs by load shape and season. Competition and cost allocation.
- 191. N.J. BPU** EM00020106, Atlantic City Electric proposed sale of fossil plants; New Jersey Ratepayer Advocate. December 2001.
- Current market value of generating plants vs. proposed purchase price.
- 192. Vt. PSB** 6545, Vermont Yankee proposed sale; Vermont Department of Public Service. January 2002.
- Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Review of auction manager's valuation of bids.
- 193. Conn. Siting Council** 217, Connecticut Light & Power proposed transmission line from Plumtree to Norwalk; Connecticut Office of Consumer Counsel. March 2002.
- Nature of transmission problems. Potential for conservation and distributed resources to defer, reduce or avoid transmission investment. CL&P transmission planning process. Joint testimony with John Plunkett.
- 194. Vt. PSB** 6596, Citizens Utilities rates; Vermont Department of Public Service. Direct, March 2002; rebuttal, May 2002.
- Review of 1991 decision to commit to long-term uneconomic purchase from Hydro Québec. Alternatives; role of transmission constraints. Calculation of present damages from imprudence.

- 195. Conn. DPUC 01-10-10, United Illuminating rate plan; Connecticut Office of Consumer Counsel. April 2002**
- Allocation of excess earnings between shareholders and ratepayers. Asymmetry in treatment of over- and under-earning. Accelerated amortization of stranded costs. Effects of power-supply developments on ratepayer risks. Effect of proposed rate plan on utility risks and required return.
- 196. Conn. DPUC 01-12-13RE01, Seabrook proposed sale; Connecticut Office of Consumer Counsel. July 2002**
- Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Assessment of valuation of purchased-power contracts.
- 197. Ont. Energy Board RP-2002-0120, review of transmission-system code; Green Energy Coalition. October 2002.**
- Cost allocation. Transmission charges. Societal cost-effectiveness. Environmental externalities.
- 198. N.J. BPU ER02080507, Jersey Central Power & Light rates; N.J. Division of the Ratepayer Advocate. Phase I December 2002; Phase II (oral) July 2003.**
- Prudence of procurement of electrical supply. Documentation of procurement decisions. Comparison of costs for subsidiaries with fixed versus flow-through cost recovery.
- 199. Conn. DPUC 03-07-02, CL&P rates; AARP. October 2003**
- Proposed distribution investments, including prudence of prior management of distribution system and utility's failure to make investments previously funded in rates. Cost controls. Application of rate cap. Legislative intent.
- 200. Conn. DPUC 03-07-01, CL&P transitional standard offer; AARP. November 2003.**
- Application of rate cap. Legislative intent.
- 201. Vt. PSB 6596, Vermont Electric Power Company and Green Mountain Power Northwest Reliability transmission plan; Conservation Law Foundation. December 2003.**
- Inadequacies of proposed transmission plan. Failure of to perform least-cost planning. Distributed resources.
- 202. Ohio PUC 03-2144-EL-ATA, Ohio Edison, Cleveland Electric, and Toledo Edison Cos. rates and transition charges; Green Mountain Energy Co. February 2004.**
- Pricing of standard-offer service in competitive markets. Critique of anticompetitive features of proposed standard-offer supply, including non-bypassable charges.

- 203. N.Y. psc 03-G-1671 & 03-S-1672**, Consolidated Edison company steam and gas rates; City of New York. Direct March 2004; rebuttal April 2004; settlement June 2004.

Prudence and cost allocation for the East River Repowering Project. Gas and steam energy conservation. Opportunities for cogeneration at existing steam plants.

- 204. N.Y. psc 04-E-0572**, Consolidated Edison rates and performance; City of New York. Direct, September 2004; rebuttal, October 2004.

Consolidated Edison's role in promoting adequate supply and demand resources. Integrated resource and T&D planning. Performance-based ratemaking and streetlighting.

- 205. Ont. Energy Board RP 2004-0188**, cost recovery and DSM for Ontario electric-distribution utilities; Green Energy Coalition. Exhibit, December 2004.

Differences in ratemaking requirements for customer-side conservation and demand management versus utility-side efficiency improvements. Recovery of lost revenues or incentives. Reconciliation mechanism.

- 206. Mass. DTE 04-65**, Cambridge Electric Light Co. streetlighting; City of Cambridge. Direct, October 2004; supplemental, January 2005.

Calculation of purchase price of street lights by the City of Cambridge.

- 207. N.Y. psc 04-W-1221**, rates, rules, charges, and regulations of United Water New Rochelle; Town of Eastchester and City of New Rochelle. Direct, February 2005.

Size and financing of proposed interconnection. Rate design. Water-mains replacement and related cost recovery. Lost and unaccounted-for water.

- 208. N.Y. psc 05-M-0090**, system-benefits charge; City of New York. Comments, March 2005.

Assessment and scope of, and potential for, New York system-benefits charges.

- 209. Md. psc 9036**, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, August 2005.

Allocation of costs. Design of rates. Interruptible and firm rates.

- 210. B.C. uc 3698388**, British Columbia Hydro resource-acquisition plan; British Columbia Sustainable Energy Association and Sierra Club of Canada BC Chapter. September 2005.

Renewable energy and DSM. Economic tests of cost-effectiveness. Costs avoided by DSM.

- 211. Conn. DPUC 05-07-18**, financial effect of long-term power contracts; Connecticut Office of Consumer Counsel. September 2005.

Assessment of effect of DSM, distributed generation, and capacity purchases on financial condition of utilities.

- 212. Conn. DPUC 03-07-01RE03 & 03-07-15RE02**, incentives for power procurement; Connecticut Office of Consumer Counsel. Direct, September 2005; Additional, April 2006.

Utility obligations for generation procurement. Application of standards for utility incentives. Identification and quantification of effects of timing, load characteristics, and product definition.

- 213. Conn. DPUC Docket 05-10-03**, Connecticut L&P; time-of-use, interruptible, and seasonal rates; Connecticut Office of Consumer Counsel. Direct and Supplemental Testimony February 2006.

Seasonal and time-of-use differentiation of generation, congestion, transmission and distribution costs; fixed and variable peak-period timing; identification of pricing seasons and seasonal peak periods; cost-effectiveness of time-of-use rates.

- 214. Ont. Energy Board Case EB-2005-0520**, Union Gas rates; School Energy Coalition. Evidence, April 2006.

Rate design related to splitting commercial rate class into two classes. New break point, cost allocation, customer charges, commodity rate blocks.

- 215. Ont. Energy Board EB-2006-0021**, Natural-gas demand-side-management generic issues proceeding; School Energy Coalition. Evidence, June 2006.

Multi-year planning and budgeting; lost-revenue adjustment mechanism; determining savings for incentives; oversight; program screening.

- 216. Ind. URC 42943 and 43046**, Vectren Energy DSM proceedings; Citizens Action Coalition. Direct, June 2006.

Rate decoupling and energy-efficiency goals.

- 217. Penn. PUC 00061346**, Duquesne Lighting; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; benefits of time-dependent pricing; appropriate metering technology; real-time rate design and customer information

- 218. Penn. PUC R-00061366 et al.**, rate-transition-plan proceedings of Metropolitan Edison and Pennsylvania Electric; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; appropriate metering technology; real-time rate design and customer information.

- 219. Conn. DPUC 06-01-08**, Connecticut L&P procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings quarterly since September 2006 to October 2013.
- Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.
- 220. Conn. DPUC 06-01-08**, United Illuminating procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings quarterly August 2006 to October 2013.
- Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.
- 221. N.Y. PSC Case No. 06-M-1017**, policies, practices, and procedures for utility commodity supply service; City of New York. Comments, November and December 2006.
- Multi-year contracts, long-term planning, new resources, procurement by utilities and other entities, cost recovery.
- 222. Conn. DPUC 06-01-08**, procurement of power for standard service and last-resort service, lessons learned; Connecticut Office Of Consumer Counsel. Comments and Technical Conferences December 2006 and January 2007.
- Sharing of data and sources; benchmark prices; need for predictability, transparency and adequate review; utility-owned resources; long-term firm contracts.
- 223. Ohio PUC PUCO 05-1444-GA-UNC**, recovery of conservation costs, decoupling, and rate-adjustment mechanisms for Vectren Energy Delivery of Ohio; Ohio Consumers' Counsel. February 2007.
- Assessing cost-effectiveness of natural-gas energy-efficiency programs. Calculation of avoided costs. Impact on rates. System benefits of DSM.
- 224. N.Y. PSC 06-G-1332**, Consolidated Edison Rates and Regulations; City of New York. March 2007.
- Gas energy efficiency: benefits to customers, scope of cost-effective programs, revenue decoupling, shareholder incentives.
- 225. Alb. EUB 1500878**, ATCO Electric rates; Association of Municipal Districts & Counties and Alberta Federation of Rural Electrical Associations. May 2007.
- Direct assignment of distribution costs to street lighting. Cost causation and cost allocation. Minimum-system and zero-intercept classification.

- 226. Conn. DPUC 07-04-24**, review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), June 2007.

Assessment of proposed capacity contracts for new combined-cycle, peakers and DSM. Evaluation of contracts for differences, modeling of energy, capacity and forward-reserve markets. Corrections of errors in computation of costs, valuation of energy-price effects of peakers, market-driven expansion plans and retirements, market response to contracted resource additions, DSM proposal evaluation.

- 227. N.Y. PSC 07-E-0524**, Consolidated Edison electric rates; City of New York. September 2007.

Energy-efficiency planning. Recovery of DSM costs. Decoupling of rates from sales. Company incentives for DSM. Advanced metering. Resource planning.

- 228. Man. PUB 136-07**, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. February 2008.

Revenue allocation, rate design, and demand-side management. Estimation of marginal costs and export revenues.

- 229. Mass. EFSB 07-7, DPU 07-58 & -59**; proposed Brockton Power Company plant; Alliance Against Power Plant Location. March 2008

Regional supply and demand conditions. Effects of plant construction and operation on regional power supply and emissions.

- 230. Conn. DPUC 08-01-01**, peaking generation projects; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), April 2008.

Assessment of proposed peaking projects. Valuation of peaking capacity. Modeling of energy margin, forward reserves, other project benefits.

- 231. Ont. Energy Board 2007-0905**, Ontario Power Generation payments; Green Energy Coalition. April 2008.

Cost of capital for Hydro and nuclear investments. Financial risks of nuclear power.

- 232. Utah PSC 07-035-93**, Rocky Mountain Power Rates; Utah Committee of Consumer Services. July 2008

Cost allocation and rate design. Cost of service. Correct classification of generation, transmission, and purchases.

- 233. Ont. Energy Board 2007-0707**, Ontario Power Authority integrated system plan; Green Energy Coalition, Penimba Institute, and Ontario Sustainable Energy Association. Evidence (with Jonathan Wallach and Richard Mazzini), August 2008.

Critique of integrated system plan. Resource cost and characteristics; finance cost. Development of least-cost green-energy portfolio.

- 234. N.Y. PSC 08-E-0596**, Consolidated Edison electric rates; City of New York. September 2008.

Estimated bills, automated meter reading, and advanced metering. Aggregation of building data. Targeted DSM program design. Using distributed generation to defer T&D investments.

- 235. Conn. DPUC 08-07-01**, Integrated resource plan; Connecticut Office of Consumer Counsel. September 2008.

Integrated resource planning scope and purpose. Review of modeling and assumptions. Review of energy efficiency, peakers, demand response, nuclear, and renewables. Structuring of procurement contracts.

- 236. Man. PUB 2008 MH EIR**, Manitoba Hydro intensive industrial rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. November 2008.

Marginal costs. Rate design. Time-of-use rates.

- 237. Md. PSC 9036**, Columbia Gas rates; Maryland Office of People's Counsel. January 2009.

Cost allocation and rate design. Critique of cost-of-service studies.

- 238. Vt. PSB 7440**, extension of authority to operate Vermont Yankee; Conservation Law Foundation and Vermont Public Interest Research Group. Direct, February 2009; Surrebuttal, May 2009.

Adequacy of decommissioning funding. Potential benefits to Vermont of revenue-sharing provision. Risks to Vermont of underfunding decommissioning fund.

- 239. N.S. UARB M01439**, Nova Scotia Power DSM and cost recovery; Nova Scotia Consumer Advocate. May 2009.

Recovery of demand-side-management costs and lost revenue.

- 240. N.S. UARB M01496**, proposed biomass project; Nova Scotia Consumer Advocate. June 2009.

Procedural, planning, and risk issues with proposed power-purchase contract. Biomass price index. Nova Scotia Power's management of other renewable contracts.

- 241. Conn. Siting Council 370A**, Connecticut Light & Power transmission projects; Connecticut Office of Consumer Counsel. July 2009. Also filed and presented in **MA EFSB 08-02**, February 2010.

Need for transmission projects. Modeling of transmission system. Realistic modeling of operator responses to contingencies

- 242. Mass. DPU 09-39**, NGrid rates; Mass. Department of Energy Resources. August 2009.
Revenue-decoupling mechanism. Automatic rate adjustments.
- 243. Utah PSC 09-035-23**, Rocky Mountain Power rates; Utah Office of Consumer Services. Direct, October 2009; rebuttal, November 2009.
Cost-of-service study. Cost allocators for generation, transmission, and substation.
- 244. Utah PSC 09-035-15**, Rocky Mountain Power energy-cost-adjustment mechanism; Utah Office of Consumer Services. Direct, November 2009; surrebutal, January 2010.
Automatic cost-adjustment mechanisms. Net power costs and related risks. Effects of energy-cost-adjustment mechanisms on utility performance.
- 245. Penn. PUC R-2009-2139884**, Philadelphia Gas Works energy efficiency and cost recovery; Philadelphia Gas Works. December 2009.
Avoided gas costs. Recovery of efficiency-program costs and lost revenues. Rate impacts of DSM.
- 246. B.C. UC 3698573**, British Columbia Hydro rates; British Columbia Sustainable Energy Association and Sierra Club British Columbia. February 2010.
Rate design and energy efficiency.
- 247. Ark. PSC 09-084-U**, Entergy Arkansas rates; National Audubon Society and Audubon Arkansas. Direct, February 2010; surrebutal, April 2010.
Recovery of revenues lost to efficiency programs. Determination of lost revenues. Incentive and recovery mechanisms.
- 248. Ark. PSC 10-010-U**, Energy efficiency; National Audubon Society and Audubon Arkansas. Direct, March 2010; reply, April 2010.
Regulatory framework for utility energy-efficiency programs. Fuel-switching programs. Program administration, oversight, and coordination. Rationale for commercial and industrial efficiency programs. Benefit of energy efficiency.
- 249. Ark. PSC 08-137-U**, Generic rate-making; National Audubon Society and Audubon Arkansas. Direct, March 2010; supplemental, October 2010; reply, October 2010.
Calculation of avoided costs. Recovery of utility energy-efficiency-program costs and lost revenues. Shareholder incentives for efficiency-program performance.

- 250. Plymouth, Mass., Superior Court** Civil Action No. PLCV2006-00651-B (Hingham Municipal Lighting Plant v. Gas Recovery Systems LLC et al.), Breach of agreement; defendants. Affidavit, May 2010.

Contract interpretation. Meaning of capacity measures. Standard practices in capacity agreements. Power-pool rules and practices. Power planning and procurement.

- 251. N.S. UARB M02961**, Port Hawkesbury biomass project; Nova Scotia Consumer Advocate. June 2010.

Least-cost planning and renewable-energy requirements. Feasibility versus alternatives. Unknown or poorly estimated costs.

- 252. Mass. DPU 10-54**, NGrid purchase of long-term power from Cape Wind; Natural Resources Defense Council et al. July 2010.

Effects of renewable-energy projects on gas and electric market prices. Impacts on system reliability and peak loads. Importance of PPAS to renewable development. Effectiveness of proposed contracts as price edges.

- 253. Md. psc 9230**, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, July 2010; rebuttal, surrebuttal, August 2010.

Allocation of gas- and electric-distribution costs. Critique of minimum-system analyses and direct assignment of shared plant. Allocation of environmental compliance costs. Allocation of revenue increases among rate classes.

- 254. Ont. Energy Board 2010-0008**, Ontario Power Generation facilities charges; Green Energy Coalition. Evidence, August 2010.

Critique of including a return on CWP in current rates. Setting cost of capital by business segment.

- 255. N.S. UARB Matter No. 03454**, Heritage Gas rates; Nova Scotia Consumer Advocate. October 2010.

Cost allocation. Cost of capital. Effect on rates of growth in sales.

- 256. Man. PUB 17/10**, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. December 2010.

Revenue-allocation and rate design. DSM program.

- 257. N.S. UARB M03665**, Nova Scotia Power depreciation rates; Nova Scotia Consumer Advocate. February 2011.

Depreciation and rates.

- 258. New Orleans City Council** UD-08-02, Entergy IRP rules; Alliance for Affordable Energy. December 2010.
Integrated resource planning: Purpose, screening, cost recovery, and generation planning.
- 259. N.S. UARB** M03665, depreciation Rates of Nova Scotia Power; Nova Scotia Consumer Advocate. February 2011.
Steam-plant retirement dates, post-retirement use, timing of decommissioning and removal costs.
- 260. N.S. UARB** M03632, renewable-energy community-based feed-in tariffs; Nova Scotia Consumer Advocate. March 2011.
Adjustments to estimate of cost-based feed-in tariffs. Rate effects of feed-in tariffs.
- 261. Mass. EFSB** 10-2/DPU 10-131, 10-132; NStar transmission; Town of Sandwich, Mass. Direct, May 2011; Surrebuttal, June 2011.
Need for new transmission; errors in load forecasting; probability of power outages.
- 262. Utah PSC** 10-035-124, Rocky Mountain Power rate case; Utah Office of Consumer Services. June 2011.
Load data, allocation of generation plants, scrubbers, power purchases, and service drops. Marginal cost study: inclusion of all load-related transmission projects, critique of minimum- and zero-intercept methods for distribution. Residential rate design.
- 263. N.S. UARB** M04104; Nova Scotia Power general rate application; Nova Scotia Consumer Advocate. August 2011.
Cost allocation: allocation of costs of wind power and substations. Rate design: marginal-cost-based rates, demand charges, time-of-use rates.
- 264. N.S. UARB** M04175, Load-retention tariff; Nova Scotia Consumer Advocate. August 2011.
Marginal cost of serving very large industrial electric loads; risk, incentives and rate design.
- 265. Ark. PSC** 10-101-R, Rulemaking re self-directed energy efficiency for large customers; National Audubon Society and Audubon Arkansas. July 2011.
Structuring energy-efficiency programs for large customers.

- 266. Okla. CC PUD 201100077**, current and pending federal regulations and legislation affecting Oklahoma utilities; Sierra Club. Comments July, October 2011; presentation July 2011.
- Challenges facing Oklahoma coal plants; efficiency, renewable and conventional resources available to replace existing coal plants; integrated environmental compliance planning.
- 267. Nevada PUC 11-08019**, integrated analysis of resource acquisition, Sierra Club. Comments, September 2011; hearing, October 2011.
- Scoping of integrated review of cost-effectiveness of continued operation of Reid Gardner 1–3 coal units.
- 268. La. PSC R-30021**, Louisiana integrated-resource-planning rules; Alliance for Affordable Energy. Comments, October 2011.
- Scoping of integrated review of cost-effectiveness of continued operation of Reid Gardner 1–3 coal units.
- 269. Okla. CC PUD 201100087**, Oklahoma Gas and Electric Company electric rates; Sierra Club. November 2011.
- Resource monitoring and acquisition. Benefits to ratepayers of energy conservation and renewables. Supply planning
- 270. Ky. PSC 2011-00375**, Kentucky utilities' purchase and construction of power plants; Sierra Club and National Resources Defense Council. December 2011.
- Assessment of resources, especially renewables. Treatment of risk. Treatment of future environmental costs.
- 271. N.S. UARB M04819**, demand-side-management plan of Efficiency Nova Scotia; Nova Scotia Consumer Advocate. May 2012.
- Avoided costs. Allocation of costs. Reporting of bill effects.
- 272. Kansas CC 12-GIMX-337-GIV**, utility energy-efficiency programs; The Climate and Energy Project. June 2012.
- Cost-benefit tests for energy-efficiency programs. Collaborative program design.
- 273. N.S. UARB M04862**, Port Hawksbury load-retention mechanism; Nova Scotia Consumer Advocate. June 2012.
- Effect on ratepayers of proposed load-retention tariff. Incremental capital costs, renewable-energy costs, and costs of operating biomass cogeneration plant.
- 274. Utah PSC 11-035-200**, Rocky Mountain Power Rates; Utah Office of Consumer Council. June 2012.
- Cost allocation. Estimation of marginal customer costs.

- 275. Ark. PSC 12-008-U**, environmental controls at Southwestern Electric Power Company's Flint Creek plant; Sierra Club. Direct, June 2012; rebuttal, August 2012; further, March 2013.
- Costs and benefits of environmental retrofit to permit continued operation of coal plant, versus other options including purchased gas generation, efficiency, and wind. Fuel-price projections. Need for transmission upgrades.
- 276. U.S. EPA EPA-R09-OAR-2012-0021**, air-quality implementation plan; Sierra Club. September 2012.
- Costs, financing, and rate effects of Apache coal-plant scrubbers. Relative incomes in service territories of Arizona Coop and other utilities.
- 277. Arkansas PSC Docket No. 07-016-U**; Entergy Arkansas' integrated resource plan; Audubon Arkansas. Comments, September 2012.
- Estimation of future gas prices. Estimation of energy-efficiency potential. Screening of resource decisions. Wind costs.
- 278. Vt. PSB 7862**, Entergy Nuclear Vermont and Entergy Nuclear Operations petition to operate Vermont Yankee; Conservation Law Foundation. October 2012.
- Effect of continued operation on market prices. Value of revenue-sharing agreement. Risks of underfunding decommissioning fund.
- 279. Man. PUB 2012-13 GRA**, Manitoba Hydro rates; Green Action Centre. November 2012.
- Estimation of marginal costs. Fuel switching.
- 280. N.S. UARB M05339**, Capital Plan of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2013.
- Economic and financial modeling of investment. Treatment of AFUDC.
- 281. N.S. UARB M05416**, South Canoe wind project of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2013.
- Revenue requirements. Allocation of tax benefits. Ratemaking.
- 282. N.S. UARB 05419**; Maritime Link transmission project and related contracts, Nova Scotia Consumer Advocate and Small Business Advocate. Direct, April 2013; supplemental (with Seth Parker), November 2013.
- Load forecast, including treatment of economy energy sales. Wind power cost forecasts. Cost effectiveness and risk of proposed project. Opportunities for improving economics of project.

- 283. Ont. Energy Board** 2012-0451/0433/0074, Enbridge Gas Greater Toronto Area project; Green Energy Coalition. June 2013, revised August 2013.
Estimating gas pipeline and distribution costs avoidable through gas DSM and curtailment of electric generation. Integrating DSM and pipeline planning.
- 284. N.S. UARB** 05092, tidal-energy feed-in-tariff rate; Nova Scotia Consumer Advocate. August 2013.
Purchase rate for test and demonstration projects. Maximizing benefits under rate-impact caps. Pricing to maximize provincial advantage as a hub for emerging tidal-power industry.
- 285. N.S. UARB** 05473, Nova Scotia Power 2013 cost-of-service study; Nova Scotia Consumer Advocate. October 2013.
Cost-allocation and rate design.
- 286. B.C. UC** 3698715 & 3698719; performance-based ratemaking plan for FortisBC companies; British Columbia Sustainable Energy Association and Sierra Club British Columbia. Direct (with John Plunkett), December 2013.
Rationale for enhanced gas and electric DSM portfolios. Correction of utility estimates of electric avoided costs. Errors in program screening. Program potential. Recommended program ramp-up rates.
- 287. Conn. PURA** Docket No. 14-01-01, Connecticut Light and Power Procurement of Standard Service and Last-Resort Service. July and October 2014.
Proxy for review of bids. Oversight of procurement and selection process.
- 288. Conn. PURA** Docket No. 14-01-02, United Illuminating Procurement of Standard Service and Last-Resort Service. January, April, July, and October 2014.
Proxy for review of bids. Oversight of procurement and selection process.
- 289. Man. PUB** 2014, need for and alternatives to proposed hydro-electric facilities; Green Action Centre. Evidence (with Wesley Stevens) February 2014.
Potential for fuel switching, DSM, and wind to meet future demand.
- 290. Utah psc** 13-035-184, Rocky Mountain Power Rates; Utah Office of Consumer Services. May 2014.
Class cost allocation. Classification and allocation of generation plant and purchased power. Principles of cost-causation. Design of backup rates.
- 291. Minn. psc** E002/GR-13-868, Northern States Power rates; Clean Energy Intervenors. Direct, June 2014; rebuttal, July 2014; surrebuttal, August 2014.
Inclining-block residential rate design. Rationale for minimizing customer charges.

- 292. Cal. PUC** Rulemaking 12-06-013, electric rates and rate structures; Natural Resources Defense Council. September 2014.
- Redesigning residential rates to simplify tier structure while maintaining efficiency and conservation incentives. Effect of marginal price on energy consumption. Realistic modeling of consumer price response. Benefits of minimizing customer charges.
- 293. Md. PSC** 9361, proposed merger of PEPCO Holdings into Exelon; Sierra Club and Chesapeake Climate Action Network. Direct, December 2014; surrebuttal, January 2015.
- Effect of proposed merger on Consumer bills, renewable energy, energy efficiency, and climate goals.
- 294. N.S. UARB** M06514, 2015 capital-expenditure plan of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2015.
- Economic evaluation of proposed projects. Treatment of AFUDC, overheads, and replacement costs of lost generation. Computation of rate effects of spending plan.
- 295. Md. PSC** 9153 et al., Maryland energy-efficiency programs; Maryland Office of People's Counsel. January 2015.
- Costs avoided by demand-side management. Demand-reduction-induced price effects.
- 296. Québec** Régie de L'énergie R-3876-2013 phase 1, Gaz Métro cost allocation and rate structure; Regroupement des organismes environnementaux en énergie and Union des consommateurs. February 2015
- Classification of the area-spanning system; minimum system and more realistic approaches. Allocation of overhead, energy-efficiency, gas-supply, engineering-and-planning, and billing costs.
- 297. Conn. PURA** Docket No. 15-01-01, Connecticut Light and Power Procurement of Standard Service and Last-Resort Service. February and July 2015.
- Proxy for review of bids. Oversight of procurement and selection process.
- 298. Conn. PURA** Docket No. 15-01-02, United Illuminating Procurement of Standard Service and Last-Resort Service. February, July, and October 2015.
- Proxy for review of bids. Oversight of procurement and selection process.
- 299. Ky. PSC** 2014-00371, Kentucky Utilities electric rates; Sierra Club. March 2015.
- Review basis for higher customer charges, including cost allocation. Design of time-of-day rates.

- 300. Ky. psc 2014-00372**, Louisville Gas and Electric electric rates; Sierra Club. March 2015.
Review basis for higher customer charges, including cost allocation. Design of time-of-day rates.
- 301. Mich. psc U-17767**, DTE Electric Company rates; Michigan Environmental Council, Sierra Club, and Natural Resource Defense Council. May 2015.
Cost effectiveness of pollution-control retrofits versus retirements. Market prices. Costs of alternatives.
- 302. N.S. UARB M06733**, supply agreement between Efficiency One and Nova Scotia Power; Nova Scotia Consumer Advocate. June 2015.
Avoided costs. Cost-effectiveness screening of DSM. Portfolio design. Affordability and bill effects.
- 303. Penn. PUC P-2014-2459362**, Philadelphia Gas Works DSM, universal-service, and energy-conservation plans; Philadelphia Gas Works. Direct, May 2015; Rebuttal, July 2015.
Avoided costs. Recovery of lost margin.
- 304. Ont. Energy Board EB-2015-0029/0049**, 2015–2020 DSM Plans Of Enbridge Gas Distribution and Union Gas, Green Energy Coalition. Evidence July 31, 2015, Corrected August 12, 2015.
Avoided costs: price mitigation, carbon prices, marginal gas supply costs, avoidable distribution costs, avoidable upstream costs (including utility-owned pipeline facilities).
- 305. PUC Ohio Case No. 14-1693-EL-RDR**, AEP Ohio Affiliate purchased-power agreement, Sierra Club. September 2015.
Economics of proposed PPA, market energy and capacity projections. Risk shifting. Lack of price stability and reliability benefits. Market viability of PPA units.
- 306. N.S. UARB Matter No. M06214**, NS Power Renewable-to-Retail rate, Nova Scotia Consumer Advocate. November 2015.
Review of proposed design of rate for third-party sales of renewable energy to retail customers. Distribution, transmission and generation charges.
- 307. PUC Texas Docket No. 44941**, El Paso Electric rates; Energy Freedom Coalition of America. December 2015.
Cost allocation and rate design. Effect of proposed DG rate on solar customers. Load shapes of residential customers with and without solar. Problems with demand charges.

- 308. N.S. UARB** Matter No. M07176, NS Power 2016 Capital Expenditures Plan, Nova Scotia Consumer Advocate. February 2016.

Economic evaluation of proposed projects, including replacement energy costs and modeling of equipment failures. Treatment of capitalized overheads and depreciation cash flow in computation of rate effects of spending plan.

- 309. Md. psc** Case No. 9406, BGE Application for recovery of Smart Meter costs, Maryland Office of People’s Counsel. Direct February 2016, Rebuttal March 2016, Surrebuttal March 2016.

Assessment of benefits of Smart Meter programs for energy revenue, load reductions and price mitigation; capacity load reductions and price mitigation; free riders and load shifting in peak-time rebate (PTR) program; cost of PTR participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

- 310. City of Austin TX**, Austin Energy 2016 Rate Review, Sierra Club and Public Citizen. May 2016

Allocation of generation costs. Residential rate design. Geographical rate differentials. Recognition of coal-plant retirement costs.

- 311. Manitoba PUB**, Manitoba Hydro Cost of Service Methodology Review, Green Action Centre. June 2016, reply August 2016.

Allocation of generation costs. Identifying generation-related transmission assets. Treatment of subtransmission. Classification of distribution lines. Allocation of distribution substations and lines. Customer allocators. Shared service drops.

- 312. Md. psc** Case No. 9418, PEPCo Application for recovery of Smart Meter costs, Maryland Office of People’s Counsel. Direct July 2016, Rebuttal August 2016, Surrebuttal September 2016.

Assessment of benefits of Smart Meter programs for energy revenue, load reductions and price mitigation; load reductions in dynamic-pricing (DP) program; cost of DP participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

- 313. Md. psc** Case No. 9424, Delmarva P&L Application for recovery of Smart Meter costs, Maryland Office of People’s Counsel. Direct September 2016, Rebuttal October 2016, Surrebuttal October 2016.

Estimation of effects of Smart Meter programs—dynamic pricing (DP), conservation voltage reduction and an informational program—on wholesale revenues, wholesale prices and avoided costs; estimating load reductions from the DP program; cost of DP participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

- 314. N.H. PUC** Docket No. DE 16-576, Alternative Net Metering Tariffs, Conservation Law Foundation. Direct October 2016, Reply December 2016.
- Framework for evaluating rates for distributed generation. Costs avoided and imposed by distributed solar. Rate design for distributed generation.
- 315. Puerto Rico Energy Commission** CEPR-AP-2015-0001, Puerto Rico Electric Power Authority rate proceeding, PR Energy Commission. Report December 2016.
- Comprehensive review of structure of electric utility, cost causation, load data, cost allocation, revenue allocation, marginal costs, retail rate designs, identification and treatment of customer subsidies, structuring rate riders, and rates for distributed generation and net metering.
- 316. N.S. UARB** Matter No. M07745, NS Power 2017 Capital Expenditures Plan, Nova Scotia Consumer Advocate. January 2017.
- Computation and presentation of rate effects. Consistency of assumed plant operation and replacement power costs. Control of total cost of small projects. Coordination of information-technology investments. Investments in biomass plant with uncertain future.
- 317. N.S. UARB** Matter No. M07746, NS Power Enterprise Resource Planning project, Nova Scotia Consumer Advocate. February 2017.
- Estimated software project costs. Costs of internal and contractor labor. Affiliate cost allocation.
- 318. N.S. UARB** Matter No. M07767, NS Power Advanced Metering Infrastructure projects, Nova Scotia Consumer Advocate. February 2017.
- Design and goals of the AMI pilot program. Procurement. Coordination with information-technology and software projects.
- 319. Québec** Régie de L'énergie R-3876-2013 phase 3A; Gaz Métro estimates of marginal O&M costs; Regroupement des organismes environnementaux en énergie. March 2017.
- Estimation of one-time, continuing and periodic customer-related operating and maintenance cost. Costs related to loads and revenues. Dealing with lumpy costs.
- 320. N.S. UARB** Matter No. M07718, NS Power Maritime Link Cost Recovery, Nova Scotia Consumer Advocate. April 2017.
- Usefulness of transmission interconnection prior to operation of the associated power plant.
- 321. Mass. DPU** 17-05, Eversource Rate Case, Cape Light Compact. May 2017.
- Critique of proposed performance-based ratemaking mechanism. Proposal for improvements.

ACRONYMS AND INITIALISMS

APS	Alleghany Power System	LRAM	Lost-Revenue-Adjustment Mechanism
ASLB	Atomic Safety and Licensing Board	NARUC	National Association of Regulatory Utility Commissioners
BEP	Board of Environmental Protection		
BPU	Board of Public Utilities	NEPOOL	New England Power Pool
BRC	Board of Regulatory Commissioners	NRC	Nuclear Regulatory Commission
CC	Corporation Commission	OCA	Office of Consumer Advocate
CMP	Central Maine Power	PSB	Public Service Board
DER	Department of Environmental Regulation	PBR	Performance-based Regulation
		PSC	Public Service Commission
DPS	Department of Public Service	PUC	Public Utility Commission
DQE	Duquesne Light	PUB	Public Utilities Board
DPUC	Department of Public Utilities Control	PURA	Public Utility Regulatory Authority
DSM	Demand-Side Management	PURPA	Public Utility Regulatory Policy Act
DTE	Department of Telecommunications and Energy	SCC	State Corporation Commission
		UARB	Utility and Review Board
EAB	Environmental Assessment Board	USAEE	U.S. Association of Energy Economists
EFSB	Energy Facilities Siting Board	UC	Utilities Commission
EFSC	Energy Facilities Siting Council	URC	Utility Regulatory Commission
EUB	Energy and Utilities Board	UTC	Utilities and Transportation Commission
FERC	Federal Energy Regulatory Commission		
ISO	Independent System Operator		



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July 9, 2015

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Re: Re: In the Matter of Ohio Power Company Revenue Neutral Residential Distribution Rate Design, Case No. 11-351-EL-AIR, Case No. 11-352-EL-AIR, Case No. 11-353-EL-ATA, Case No. 11-354-EL-ATA, Case No. 11-356-EL-AAM, Case No. 11-358-EL-AAM.

Dear Docketing Chief McNeal:

Background

On December 14, 2011, the Commission issued an Opinion and Order in these cases requiring Ohio Power Company (AEP Ohio or the Company) to update its cost-of-service study and file the updated study in this proceeding to review residential rate design at the end of the 3-year pilot revenue decoupling program. In addition, the Commission directed the Company to file, in Case No. 10-3126-EL-UNC, metrics to evaluate the success of the pilot program. The Company filed in that case as directed and that case is now closed based on the Commission determining that a straight fixed variable approach was to be filed by the electric utilities in their next base case. The Commission then narrowed its focus in the February 14, 2012 Entry on Rehearing in Case No. 11-351-EL-AIR determining that the Company recognize the Commission's focus on moving to a straight-fixed-variable rate in the future. As such the Company provides the following information to compare the pilot throughput balancing adjustment rider to a straight fixed variable rate design in compliance with the Commission's order in Case No. 11-351-EL-AIR.

Updated Cost-of-Service Study

Consistent with the Commission's directives, the Company is submitting a jurisdictional cost-of-service study for calendar year 2014 as Attachment 1 of this filing. This cost-of-service study does not include all adjustments typically made during a distribution rate case. It does, however, include an adjustment to remove the Company's revenues under the Pilot Throughput Balancing Adjustment Rider (PTBAR) and an adjustment to gross 2014 revenues to the level that would have been achieved had the Company instituted a Straight Fixed Variable (SFV) rate design.

Distribution Revenues

The Company has included the following riders in the study's Distribution per Books amount for the Distribution Firm Sales and Rider Revenues Line:

Universal Service Fund Rider
KWH Tax Rider
Residential Distribution Credit Rider
Pilot Throughput Balancing Adjustment Rider
Deferred Asset Phase-In Rider
Transmission Cost Recovery Rider*
Economic Development Rider
Enhanced Service Reliability Rider
GridSMART Phase 1 Rider
Distribution Investment Rider
Storm Damage Recovery Rider
Energy Efficiency and Peak Demand Reduction Cost Rider*

* The Transmission Cost Recovery Rider and the Energy Efficiency and Peak Demand Reduction Cost Rider were removed from revenues via adjustments included in Column 3 of Attachment 1 – Distribution Fixed, Known & Measurable Adjustments.

SFV Rate Design

The use of a Straight Fixed Variable rate design yields a Residential distribution charge of \$27.24 per bill for a standard residential customer and a GS-1 distribution charge of \$14.81 per bill for standard GS-1 customer. The rate design, which reflects the revenue requirements and billing determinants from Case Nos. 11-351-EL-AIR and 11-352-EL-AIR, along with the cost-of-service revenue adjustment are included in Attachment 2 of this filing.

Change in Pilot Throughput Balancing Adjustment Rider

The table below summarizes the effect of the net adjustments that remove the PTBAR accrual and replace it with an increase in revenues that would have resulted from the use of a SFV rate design for Residential and GS-1 customers.

Adjusted Operating Revenues – Sales of Electricity	\$1,214,291,151	100%
Adjustment to Remove PTBAR Revenues	22,989,212	2%
Adjusted Distribution Revenues, excl. PTBAR	1,191,301,939	98%
Distribution Adjustment to Reflect SFV*	26,184,024	2%
Adjusted Operating Revenues – After SFV Adjustment	\$1,217,485,964	100%

*Calculated in Attachment 2 of this filing

Barcy F. McNeal

July 9, 2015

Page 3

The Company provides this information as indicated by the Commission as a compliance filing related to the enumerated cases and is not seeking any change to the Pilot Throughput Balancing Adjustment Rider or other rates at this time.

Cordially,

/s/Matthew J. Satterwhite

Matthew J. Satterwhite

Senior Counsel

cc: Parties of Record

Ohio Power Company - Distribution
Jurisdictional Separation Study
Twelve Months Ended December 31, 2014

Line No.	Description	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		DISTRIBUTION PER BOOKS	DISTRIBUTION KNOWN & MEASURABLE ADJUSTMENTS	DISTRIBUTION AFTER ADJUSTMENT	DISTRIBUTION REMOVE FTBAR ADJUSTMENT	DISTRIBUTION AFTER FTBAR ADJUSTMENT	DISTRIBUTION TO REFLECT SFV ADJUSTMENT	DISTRIBUTION AFTER SFV ADJUSTMENT	ALLOCATOR		
1	Operating Revenues - Sale of Electricity	2,864,176,800	(1,649,885,649)	1,214,291,151	(22,989,212)	1,191,301,939	26,184,024	1,217,485,964			
2	Other Electric Operating Revenues	(37,578,867)	72,811,190	35,232,324	0	35,232,324	0	35,232,324			
3	Non-Firm Sales Revenues	387,387,235	(387,387,235)	0	0	0	0	0			
4	Total Operating Revenues	3,213,985,168	(1,964,461,693)	1,249,523,475	(22,989,212)	1,226,534,263	26,184,024	1,252,718,287			
5	Operation and Maintenance Expenses										
6	Power Production	1,474,368,257	(1,438,651,850)	35,716,407	0	35,716,407	0	35,716,407			
7	Transmission	272,544,016	(272,544,016)	0	0	0	0	0			
8	Distribution	186,235,870	(255,290)	187,980,560	0	187,980,560	0	187,980,560			
9	Customer Accounts	239,731,633	(239,731,633)	0	0	0	0	0			
10	Customer Service & Information	80,888,992	(71,913,433)	8,975,559	0	8,975,559	0	8,975,559			
10	Sales Expense	2,236,374	0	2,236,374	0	2,236,374	0	2,236,374			
11	Administrative and General	74,864,933	74,864,933	0	0	74,864,933	0	74,864,933			
12	Total Operation and Maintenance Expense	2,332,870,075	(1,783,364,598)	549,505,487	0	549,505,487	0	549,505,487			
13	Depreciation and Amortization Expense	137,337,855	0	137,337,855	0	137,337,855	0	137,337,855			
14	Regulatory Debits/Credits	109,974,399	(107,272,463)	2,701,946	(876,914)	1,825,032	0	1,825,032			
15	Taxes Other than Income	298,559,293	0	298,559,293	0	298,559,293	0	298,559,293			
16	Other	30,232,188	0	30,232,188	0	30,232,188	0	30,232,188			
17	Total Other Expenses	576,103,734	(107,272,463)	468,831,281	(876,914)	467,954,367	0	467,954,367			
18	Net Operating Income Before Income Tax	305,011,359	(73,824,652)	231,186,707	(22,112,298)	209,074,409	26,184,024	235,258,433			
19	State Income Tax	(4,868,952)	325,447	(4,543,505)	(206,820)	(4,750,125)	254,771	(4,495,354)			
20	Deferred State Income Tax	16,658,726	(1,043,781)	15,614,965	(8,532)	15,606,433	0	15,606,433			
21	Total State Income Tax	11,789,774	(718,314)	11,071,460	(215,152)	10,856,308	254,771	11,111,079			
22	Federal Income Tax										
23	Current Federal Income Tax	38,407,932	11,592,824	50,000,756	(7,360,067)	42,640,689	9,075,239	51,715,928			
24	Deferred Federal Income Tax	30,761,505	(37,180,042)	(6,418,537)	(303,934)	(6,722,471)	0	(6,722,471)			
25	Deferred Investment Tax Credit	(92,654)	0	(92,654)	0	(92,654)	0	(92,654)			
26	Total Federal Income Taxes	69,076,784	(25,587,218)	43,489,568	(7,664,001)	35,825,565	9,075,239	44,900,804			
27	Net Operating Income	224,144,801	(47,519,120)	176,625,681	(14,233,145)	162,392,536	16,854,014	179,246,551			
28	Electric Plant in Service - Original Cost	4,383,785,604	0	4,383,785,604	0	4,383,785,604	0	4,383,785,604			
29	Accumulated Provision for Depreciation & Amortization	(1,611,696,149)	0	(1,611,696,149)	0	(1,611,696,149)	0	(1,611,696,149)			
30	Construction Work in Progress	113,868,345	0	113,868,345	0	113,868,345	0	113,868,345			
31	Working Capital Requirement	9,799,995	0	9,799,995	0	9,799,995	0	9,799,995			
32	Other Rate Base Offsets	(835,390,008)	0	(835,390,008)	0	(835,390,008)	0	(835,390,008)			
33	Rate Base	2,060,367,786	0	2,060,367,786	0	2,060,367,786	0	2,060,367,786			

Ohio Power Company - Distribution
Jurisdictional Separation Study
Twelve Months Ended December 31, 2014

Line No.	Description (1)	DISTRIBUTION PER BOOKS (2)	DISTRIBUTION FIXED, KNOWN & MEASURABLE ADJUSTMENTS (3)	DISTRIBUTION AFTER ADJUSTMENT (4)	DISTRIBUTION ADJUSTMENT TO REMOVE PTBAR (5)	DISTRIBUTION AFTER PTBAR ADJUSTMENT (6)	DISTRIBUTION ADJUSTMENT TO REFLECT SFV (7)	DISTRIBUTION AFTER SFV ADJUSTMENT (8)	ALLOCATOR (9)	% (10)
1	Development of Rate Base									
2	Electric Plant in Service									
3	Intangible Plant									
4	A301 Organization costs	3,379	0	3,379	0	3,379	0	3,379	Direct	
5	A302 Franchises and Consents	4,700	0	4,700	0	4,700	0	4,700	Direct	
6	A303 Miscellaneous Intangible Plant	81,456,551	0	81,456,551	0	81,456,551	0	81,456,551	Direct	
7	Total Intangible Plant	81,464,630	0	81,464,630	0	81,464,630	0	81,464,630		
8	Production Plant									
9	Steam & Hydraulic (A300s to A340s)	0	0	0	0	0	0	0	N/A	
10	Total Production Plant	0	0	0	0	0	0	0		
11	Transmission Plant									
12	A350 Land and Land Rights	0	0	0	0	0	0	0	N/A	
13	A352 Structures and Improvements	0	0	0	0	0	0	0	N/A	
14	A353 Station Equipment	0	0	0	0	0	0	0	N/A	
15	A354 Towers and Fixtures	0	0	0	0	0	0	0	N/A	
16	A355 Poles and Fixtures	0	0	0	0	0	0	0	N/A	
17	A356 O.H. Conductors & Devices	0	0	0	0	0	0	0	N/A	
18	A357 Underground Conduit	0	0	0	0	0	0	0	N/A	
19	A358 Underground Conductors	0	0	0	0	0	0	0	N/A	
20	A359 Roads and Trails	0	0	0	0	0	0	0	N/A	
21	Total Transmission Plant	0	0	0	0	0	0	0		

Ohio Power Company - Distribution
Jurisdictional Separation Study
Twelve Months Ended December 31, 2014

Line No.	Description (1)	DISTRIBUTION PER BOOKS (2)	DISTRIBUTION FIXED, KNOWN & MEASURABLE ADJUSTMENTS (3)	DISTRIBUTION AFTER ADJUSTMENT (4)	DISTRIBUTION REMOVE PTBAR ADJUSTMENT TO (5)	DISTRIBUTION AFTER PTBAR ADJUSTMENT (6)	DISTRIBUTION ADJUSTMENT TO REFLECT SFV (7)	DISTRIBUTION AFTER SFV ADJUSTMENT (8)	ALLOCATOR (9)	% (10)
1	Distribution Plant	57,770,583	0	57,770,583	0	57,770,583	0	57,770,583	Direct	
2	A360 Land and Land Rights	20,432,375	0	20,432,375	0	20,432,375	0	20,432,375	Direct	
3	A361 Structures and Improvements	594,742,798	0	594,742,798	0	594,742,798	0	594,742,798	Direct	
4	A362 Station Equipment	5,069,926	0	5,069,926	0	5,069,926	0	5,069,926	Direct	
5	A363 Storage Battery Equipment	654,180,595	0	654,180,595	0	654,180,595	0	654,180,595	Direct	
6	A364 Poles, Towers & Fixtures	672,468,181	0	672,468,181	0	672,468,181	0	672,468,181	Direct	
7	A365 O.H. Conductors & Devices	205,104,904	0	205,104,904	0	205,104,904	0	205,104,904	Direct	
8	A366 Underground Conduits	567,345,527	0	567,345,527	0	567,345,527	0	567,345,527	Direct	
9	A367 U.G. Conductors & Devices	716,261,529	0	716,261,529	0	716,261,529	0	716,261,529	Direct	
10	A368 Line Transformers	315,224,716	0	315,224,716	0	315,224,716	0	315,224,716	Direct	
11	A369 Services	182,207,258	0	182,207,258	0	182,207,258	0	182,207,258	Direct	
12	A370 Meters	54,332,413	0	54,332,413	0	54,332,413	0	54,332,413	Direct	
13	A371 Initial. on Customer Prem.	103,793	0	103,793	0	103,793	0	103,793	Direct	
14	A372 Leased Prop. on Cust. Premises	38,739,735	0	38,739,735	0	38,739,735	0	38,739,735	Direct	
15	A373 Street Lights	4,083,984,333	0	4,083,984,333	0	4,083,984,333	0	4,083,984,333	Direct	
16	Total Distribution Plant	7,896,622	0	7,896,622	0	7,896,622	0	7,896,622	Direct	
17	General Plant	123,480,728	0	123,480,728	0	123,480,728	0	123,480,728	Direct	
18	A389 Land and Land Rights	4,714,238	0	4,714,238	0	4,714,238	0	4,714,238	Direct	
19	A390 Structures and Improvements	12,731	0	12,731	0	12,731	0	12,731	Direct	
20	A391 Office Furniture & Equip.	414,525	0	414,525	0	414,525	0	414,525	Direct	
21	A392 Transportation Equipment	23,482,002	0	23,482,002	0	23,482,002	0	23,482,002	Direct	
22	A393 Stores Equipment	190,418	0	190,418	0	190,418	0	190,418	Direct	
23	A394 Tools, Shop & Garage Equip.	4,943	0	4,943	0	4,943	0	4,943	Direct	
24	A395 Laboratory Equipment	54,989,338	0	54,989,338	0	54,989,338	0	54,989,338	Direct	
25	A396 Power Operated Equipment	2,053,235	0	2,053,235	0	2,053,235	0	2,053,235	Direct	
26	A397 Communication Equipment	0	0	0	0	0	0	0	Direct	
27	A398 Misc. Equipment	461,283	0	461,283	0	461,283	0	461,283	Direct	
28	A399 Other Property - Land	0	0	0	0	0	0	0	Direct	
29	A39910 Other Property/ Land Rights	0	0	0	0	0	0	0	Direct	
30	A39919 ARO General Plant	217,700,063	0	217,700,063	0	217,700,063	0	217,700,063	Direct	
31	A39930 Other Tangible Property	4,383,149,026	0	4,383,149,026	0	4,383,149,026	0	4,383,149,026	Direct	
32	Total General Plant	636,578	0	636,578	0	636,578	0	636,578	Direct	
33	Total Electric Plant in Service (101 & 106)	4,383,785,604	0	4,383,785,604	0	4,383,785,604	0	4,383,785,604	Direct	
34	Electric Plant Acquisition Adjustment (114)	0	0	0	0	0	0	0	Direct	
35	Total Electric Utility Plant	4,383,785,604	0	4,383,785,604	0	4,383,785,604	0	4,383,785,604	Direct	

Ohio Power Company - Distribution
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Twelve Months Ended December 31, 2014

Line No.	Description (1)	DISTRIBUTION PER BOOKS (2)	DISTRIBUTION FIXED, KNOWN & MEASURABLE ADJUSTMENTS (3)	DISTRIBUTION AFTER ADJUSTMENT (4)	DISTRIBUTION ADJUSTMENT TO REMOVE PTBAR (5)	DISTRIBUTION AFTER PTBAR ADJUSTMENT (6)	DISTRIBUTION ADJUSTMENT TO REFLECT SFV (7)	DISTRIBUTION AFTER SFV ADJUSTMENT (8)	ALLOCATOR (9)	% (10)
1	Accumulated Provision for Depreciation	0	0	0	0	0	0	0	N/A	
2	Steam & Hydraulic	0	0	0	0	0	0	0		
3	Total Production Plant	0	0	0	0	0	0	0		
4	Transmission	0	0	0	0	0	0	0	N/A	
5	Total Transmission Plant	0	0	0	0	0	0	0		
6	Distribution	(1,454,754,803)	0	(1,454,754,803)	0	(1,454,754,803)	0	(1,454,754,803)	Direct	
7	Total Distribution Plant	(1,454,754,803)	0	(1,454,754,803)	0	(1,454,754,803)	0	(1,454,754,803)		
8	General	(89,220,227)	0	(89,220,227)	0	(89,220,227)	0	(89,220,227)	Direct	
9	Total General Plant	(89,220,227)	0	(89,220,227)	0	(89,220,227)	0	(89,220,227)		
10	Total Accumulated Provision for Depreciation (108)	(1,543,975,030)	0	(1,543,975,030)	0	(1,543,975,030)	0	(1,543,975,030)		
11	Accumulated Provision for Amortization									
12	Intangible	(58,146,872)	0	(58,146,872)	0	(58,146,872)	0	(58,146,872)	Direct	
13	Total Intangible	(58,146,872)	0	(58,146,872)	0	(58,146,872)	0	(58,146,872)		
14	Steam & Hydraulic	0	0	0	0	0	0	0	N/A	
15	Total Production Plant	0	0	0	0	0	0	0		
16	Transmission Plant	0	0	0	0	0	0	0	N/A	
17	Total Transmission Plant	0	0	0	0	0	0	0		
18	Distribution	0	0	0	0	0	0	0		
19	Total Distribution Plant	0	0	0	0	0	0	0		
20	General	(8,986,318)	0	(8,986,318)	0	(8,986,318)	0	(8,986,318)	Direct	
21	Total General Plant	(8,986,318)	0	(8,986,318)	0	(8,986,318)	0	(8,986,318)		
22	Total Accumulated Provision for Amortization (111)	(67,133,190)	0	(67,133,190)	0	(67,133,190)	0	(67,133,190)		
23	Amortization-Plant Acquisition Adjustment (115)	(587,929)	0	(587,929)	0	(587,929)	0	(587,929)	Direct	
24	Total Acc Prov Depreciation and Amortization	(1,611,696,149)	0	(1,611,696,149)	0	(1,611,696,149)	0	(1,611,696,149)		
25	Net Electric Plant in Service	2,772,089,455	0	2,772,089,455	0	2,772,089,455	0	2,772,089,455		
26	Construction Work in Progress (107)	113,868,345	0	113,868,345	0	113,868,345	0	113,868,345	Direct	

Ohio Power Company - Distribution
Jurisdictional Separation Study
Twelve Months Ended December 31, 2014

Line No.	Description (1)	DISTRIBUTION PER BOOKS (2)	DISTRIBUTION FIXED, KNOWN & MEASURABLE ADJUSTMENTS (3)			DISTRIBUTION AFTER ADJUSTMENT (4)	DISTRIBUTION REMOVE PTBAR ADJUSTMENT TO (5)	DISTRIBUTION AFTER PTBAR ADJUSTMENT (6)	DISTRIBUTION ADJUSTMENT TO REFLECT SFV (7)	DISTRIBUTION AFTER SFV ADJUSTMENT (8)	ALLOCATOR (9)	% (10)
			DISTRIBUTION PER BOOKS	DISTRIBUTION ADJUSTMENTS	DISTRIBUTION AFTER ADJUSTMENT							
1	Working Capital Requirements											
2	Assets											
3	Uncollectibles (144)	0	0	0	0	0	0	0	0	0	0	0
4	Fuel Inventory (151, 152)	0	0	0	0	0	0	0	0	0	0	0
5	Materials & Supplies Held for Normal Ops (154, 163)	2,538,347	0	2,538,347	0	2,538,347	0	2,538,347	0	2,538,347	Direct/Normal Ops	9.01%
6	Prepayments-Other (165)	7,261,648	0	7,261,648	0	7,261,648	0	7,261,648	0	7,261,648	Direct	
7	Other Current Assets	0	0	0	0	0	0	0	0	0	Direct	
8	Total Working Capital Requirements	9,799,995	0	9,799,995	0	9,799,995	0	9,799,995	0	9,799,995		
9	Other Rate Base Offsets											
10	Customer Deposits (235)	(53,922,061)	0	(53,922,061)	0	(53,922,061)	0	(53,922,061)	0	(53,922,061)	Direct	
11	Customer Advances (252)	(250,000)	0	(250,000)	0	(250,000)	0	(250,000)	0	(250,000)	Direct	
12	Prepayments-Pension (1650010/1650019/1650020)	173,839,011	0	173,839,011	0	173,839,011	0	173,839,011	0	173,839,011	Direct	
13	Deferred Taxes - Federal (190.1)	122,690,217	0	122,690,217	0	122,690,217	0	122,690,217	0	122,690,217	Direct	
14	Deferred Taxes - State (190.1)	4,453,049	0	4,453,049	0	4,453,049	0	4,453,049	0	4,453,049	Direct	
15	Deferred Taxes (281.1)	0	0	0	0	0	0	0	0	0	Direct	
16	Deferred Taxes (282.1)	(586,506,790)	0	(586,506,790)	0	(586,506,790)	0	(586,506,790)	0	(586,506,790)	Direct	
17	Deferred Taxes - Federal (283.1)	(470,728,955)	0	(470,728,955)	0	(470,728,955)	0	(470,728,955)	0	(470,728,955)	Direct	
18	Deferred Taxes - State (283.1)	(24,861,533)	0	(24,861,533)	0	(24,861,533)	0	(24,861,533)	0	(24,861,533)	Direct	
19	Deferred Investment Tax Credits (255)	(102,946)	0	(102,946)	0	(102,946)	0	(102,946)	0	(102,946)	Direct -46/(1) portion	
20	Total Other Rate Base Offsets	(835,390,008)	0	(835,390,008)	0	(835,390,008)	0	(835,390,008)	0	(835,390,008)		
21	Total Rate Base	2,060,367,786	0	2,060,367,786	0	2,060,367,786	0	2,060,367,786	0	2,060,367,786		

Ohio Power Company - Distribution
Jurisdictional Separation Study
Twelve Months Ended December 31, 2014

Line No.	Description	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		DISTRIBUTION PER BOOKS	DISTRIBUTION FIXED, KNOWN & MEASURABLE ADJUSTMENTS	DISTRIBUTION AFTER ADJUSTMENT	DISTRIBUTION REMOVE PTBAR ADJUSTMENT TO	DISTRIBUTION AFTER PTBAR ADJUSTMENT	DISTRIBUTION REFLECT SFV ADJUSTMENT TO	DISTRIBUTION AFTER SFV ADJUSTMENT	ALLOCATOR	%	
1	Distribution Firm Sales & Rider Revenue	1,321,964,184	(130,662,245)	1,191,301,939	0	1,191,301,939	26,184,024	1,217,485,964	Specific	100.0%	
2	Other Generation and Transmission Revenues	1,519,223,404	(1,519,223,404)	0	0	0	0	0	Specific	100.0%	
3	Pilot Throughput Balancing Adjustment Rider	22,989,212	0	22,989,212	(22,989,212)	0	0	0	Specific	100.0%	
4	Total Firm Sales	2,864,176,800	(1,649,885,649)	1,214,291,151	(22,989,212)	1,191,301,939	26,184,024	1,217,485,964			
5	Sales for Resale	387,387,235	(387,387,235)	0	0	0	0	0			
6	447 - Sales for Resale	387,387,235	(387,387,235)	0	0	0	0	0			
7	Total Sales for Resale	387,387,235	(387,387,235)	0	0	0	0	0			
8	Other Operating Revenues	3,062,403	0	3,062,403	0	3,062,403	0	3,062,403	Specific	100.0%	
9	450-Forfeited Discounts	7,074,607	0	7,074,607	0	7,074,607	0	7,074,607	Specific	98.5%	
10	451-Miscellaneous Service Revenues	10,137,010	0	10,137,010	0	10,137,010	0	10,137,010			
11	Subtotal Other Operating Revenues	20,199,977	(255,290)	19,944,687	0	19,944,687	0	19,944,687			
12	Rent from Electric Property	4,993,525	(255,290)	4,738,236	0	4,738,236	0	4,738,236			
13	4541-Rent-Assoc Cos	60,230	0	60,230	0	60,230	0	60,230	Specific	4.8%	
14	4542-Rent-Non-Assoc Cos	283,945	0	283,945	0	283,945	0	283,945	Specific	32.8%	
15	4544-Rent From Elect Prop-ABD-Nonaf	14,862,277	0	14,862,277	0	14,862,277	0	14,862,277	Specific	100.0%	
16	4545-Rent from Elec Prop-Pole Aitch	20,199,977	(255,290)	19,944,687	0	19,944,687	0	19,944,687			
17	Total Rent from Electric Property	20,199,977	(255,290)	19,944,687	0	19,944,687	0	19,944,687			
18	Other Electric Revenue	1,203,159	0	1,203,159	0	1,203,159	0	1,203,159	Specific	100.0%	
19	456-Other Electric Revenue - Distribution	2,589,516	0	2,589,516	0	2,589,516	0	2,589,516	Specific	80.7%	
20	456.0015 Other Electric Revenues - ABD	2,300	0	2,300	0	2,300	0	2,300	Specific	91.0%	
21	456.0041 Misc. Revenue - Non-Affiliated	19,096,848	(19,096,848)	0	0	0	0	0	Specific	100.0%	
22	456.0180 Amort of Defer Equity Inc	1,355,652	0	1,355,652	0	1,355,652	0	1,355,652	Specific	100.0%	
23	456.1027 PJM Tranns Dist/Meter - Non-Aff	(89,404,764)	89,404,764	0	0	0	0	0	Specific	100.0%	
24	456-Other Electric Revenue - Non-Jurisdictional TCRR	(2,758,564)	2,758,564	0	0	0	0	0	Specific	102.8%	
25	456-Other Electric Revenue - Non-Jurisdictional	(67,915,853)	73,066,480	5,150,627	0	5,150,627	0	5,150,627	Specific	-0.9%	
26	Total Other Electric Revenues	(37,578,867)	72,811,190	35,232,324	0	35,232,324	0	35,232,324			
27	Total Other Operating Revenues	3,213,985,168	(1,964,461,693)	1,249,523,475	(22,989,212)	1,226,534,263	26,184,024	1,252,718,287			

Ohio Power Company - Distribution
Jurisdictional Separation Study
Twelve Months Ended December 31, 2014

Line No.	Description (1)	DISTRIBUTION PER BOOKS (2)	DISTRIBUTION FIXED, KNOWN & MEASURABLE ADJUSTMENTS (3)	DISTRIBUTION AFTER ADJUSTMENT (4)	DISTRIBUTION REMOVE PTBAR ADJUSTMENT (5)	DISTRIBUTION AFTER PTBAR ADJUSTMENT (6)	DISTRIBUTION TO REFLECT SFV (7)	DISTRIBUTION AFTER SFV ADJUSTMENT (8)	ALLOCATOR (9)	% (10)
1	Power Production Expenses									
2	Steam Operation & Maintenance (500-514)	0	0	0	0	0	0	0	0	N/A
3	Hydraulic Operations & Maintenance (535-545)	0	0	0	0	0	0	0	0	N/A
4	Other Production Operations & Maintenance (546-554)	0	0	0	0	0	0	0	0	N/A
5	Subtotal Production Expenses	0	0	0	0	0	0	0	0	
6	Other Power Supply Expense									
7	555-Purchased Power	1,417,016,841	(1,417,016,841)	0	0	0	0	0	0	Specific
8	555.0110 Purchased Power Discounts	35,716,407	0	35,716,407	0	35,716,407	0	35,716,407	0	Specific
9	556-Sys Control & Load Dispatching	0	0	0	0	0	0	0	0	N/A
10	557- Other Expenses	21,635,009	(21,635,009)	0	0	0	0	0	0	Specific
11	Total Other Power Supply Expense	1,474,368,257	(1,438,651,850)	35,716,407	0	35,716,407	0	35,716,407	0	100.0%
12	Total Production O&M Expense	1,474,368,257	(1,438,651,850)	35,716,407	0	35,716,407	0	35,716,407	0	99.97%
13	Transmission Expense									
14	560-Supervision & Engineering	0	0	0	0	0	0	0	0	N/A
15	561-Load Dispatching	3,786,658	(3,786,658)	0	0	0	0	0	0	Specific
16	562-Station Equipment	0	0	0	0	0	0	0	0	N/A
17	563-Overhead Lines	0	0	0	0	0	0	0	0	N/A
18	564-Underground Lines	0	0	0	0	0	0	0	0	N/A
19	565-Transmission of Electricity by Others	266,463,122	(266,463,122)	0	0	0	0	0	0	N/A
20	566-Misc Transmission	0	0	0	0	0	0	0	0	N/A
21	567-Rents	0	0	0	0	0	0	0	0	N/A
22	575-Regional Market Expenses	2,294,236	(2,294,236)	0	0	0	0	0	0	Specific
23	Total Transmission Operation Expense	272,544,016	(272,544,016)	0	0	0	0	0	0	100.0%
24	568-Supervision & Engineering	0	0	0	0	0	0	0	0	N/A
25	569-Structures	0	0	0	0	0	0	0	0	N/A
26	570-Station Equipment	0	0	0	0	0	0	0	0	N/A
27	571-Overhead Lines	0	0	0	0	0	0	0	0	N/A
28	572-Underground Lines	0	0	0	0	0	0	0	0	N/A
29	573-Misc Transmission Expenses	0	0	0	0	0	0	0	0	N/A
30	Total Transmission Maintenance Expense	0	0	0	0	0	0	0	0	
31	Total Transmission O&M Expense	272,544,016	(272,544,016)	0	0	0	0	0	0	38.8%

Ohio Power Company - Distribution
Jurisdictional Separation Study
Twelve Months Ended December 31, 2014

Line No.	Description (1)	DISTRIBUTION PER BOOKS (2)	DISTRIBUTION FIXED, KNOWN & MEASURABLE ADJUSTMENTS (3)	DISTRIBUTION AFTER ADJUSTMENT (4)	DISTRIBUTION TO REMOVE PTBAR ADJUSTMENT (5)	DISTRIBUTION AFTER PTBAR ADJUSTMENT (6)	DISTRIBUTION TO REFLECT SFV ADJUSTMENT (7)	DISTRIBUTION AFTER SFV ADJUSTMENT (8)	ALLOCATOR (9)	% (10)
1	Distribution Expense									
2	580-Supervision & Engineering	7,761,729	0	7,761,729	0	7,761,729	0	7,761,729	Specific	100.0%
3	581-Load Dispatching	21,843	0	21,843	0	21,843	0	21,843	Specific	100.0%
4	582-Station Equipment	1,721,942	0	1,721,942	0	1,721,942	0	1,721,942	Specific	100.0%
5	583-Overhead Lines	1,513,688	0	1,513,688	0	1,513,688	0	1,513,688	Specific	100.0%
6	584-Underground Lines	1,512,346	0	1,512,346	0	1,512,346	0	1,512,346	Specific	100.0%
7	585-Street & Area Lighting	161,026	0	161,026	0	161,026	0	161,026	Specific	100.0%
8	586-Meters	1,156,209	0	1,156,209	0	1,156,209	0	1,156,209	Specific	100.0%
9	587-Customer Installations	204,963	0	204,963	0	204,963	0	204,963	Specific	100.0%
10	588.0000 Miscellaneous Distribution Exp	41,874,319	0	41,874,319	0	41,874,319	0	41,874,319	Specific	100.0%
11	588.0004 gSMART-OvUnd Misc Dist Exp	(22,939,208)	0	(22,939,208)	0	(22,939,208)	0	(22,939,208)	Specific	100.0%
12	589.0001 Rents - Nonassociated	5,099,777	0	5,099,777	0	5,099,777	0	5,099,777	Specific	100.0%
13	589.0002 Rents - Associated	333,140	0	77,850	0	77,850	0	77,850	Specific	100.0%
14	Total Distribution Operation	38,421,774	(255,290)	38,166,484	0	38,166,484	0	38,166,484		
15	590-Supervision & Engineering	539,848	0	539,848	0	539,848	0	539,848	Specific	100.0%
16	591-Structures	81,789	0	81,789	0	81,789	0	81,789	Specific	100.0%
17	592-Station Equipment	5,696,447	0	5,696,447	0	5,696,447	0	5,696,447	Specific	100.0%
18	593.0000 Maintenance of Overhead Lines	124,902,389	0	124,902,389	0	124,902,389	0	124,902,389	Specific	100.0%
19	593.0008 Storm Damage - OvUnd	2,939,426	0	2,939,426	0	2,939,426	0	2,939,426	Specific	100.0%
20	593.0009 ESRR-OvUnd Maint Own Lines	332,661	0	332,661	0	332,661	0	332,661	Specific	100.0%
21	593.0010 Storm Expense Amortization	1,090	0	1,090	0	1,090	0	1,090	Specific	100.0%
22	594-Underground Lines	8,878,900	0	8,878,900	0	8,878,900	0	8,878,900	Specific	100.0%
23	595-Line Transformers	2,022,271	0	2,022,271	0	2,022,271	0	2,022,271	Specific	100.0%
24	596-Street & Area Lighting	446,597	0	446,597	0	446,597	0	446,597	Specific	100.0%
25	597-Meters	617,226	0	617,226	0	617,226	0	617,226	Specific	100.0%
26	598-Misc Distribution Plant	3,355,452	0	3,355,452	0	3,355,452	0	3,355,452	Specific	100.0%
27	Total Distribution Maintenance	149,814,096	0	149,814,096	0	149,814,096	0	149,814,096		
28	Total Distribution Expense	186,235,870	(255,290)	187,980,580	0	187,980,580	0	187,980,580		

Ohio Power Company - Distribution
Jurisdictional Separation Study
Twelve Months Ended December 31, 2014

Line No.	Description	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		DISTRIBUTION PER BOOKS	DISTRIBUTION FIXED, KNOWN & MEASURABLE ADJUSTMENTS	DISTRIBUTION AFTER ADJUSTMENT	DISTRIBUTION AFTER REMOVE PTBAR ADJUSTMENT TO	DISTRIBUTION AFTER PTBAR ADJUSTMENT	DISTRIBUTION AFTER SFV ADJUSTMENT	ALLOCATOR	%		
1	Customer Accounts Expense										
2	901-Supervision & Engineering	1,271,754	0	1,271,754	0	1,271,754	0	1,271,754	Specific		100.0%
3	902-Meter Reading	7,804,086	0	7,804,086	0	7,804,086	0	7,804,086	Specific		100.0%
4	903-Customer Records & Collection Expense	39,422,551	0	39,422,551	0	39,422,551	0	39,422,551	Specific		100.0%
5	904-Uncollectible Accounts	(366,011)	0	(366,011)	0	(366,011)	0	(366,011)	Specific		100.0%
6	904.0002-Uncoil Accts - Pct Income Plan	191,375,823	0	191,375,823	0	191,375,823	0	191,375,823	Specific		100.0%
7	905-Misc Customer Accounts	223,430	0	223,430	0	223,430	0	223,430	Specific		100.0%
8	Total Customer Accounts	239,731,633	0	239,731,633	0	239,731,633	0	239,731,633			
9	Customer Service & Information Expense										
10	907-Supervision	5,612,211	0	5,612,211	0	5,612,211	0	5,612,211	Specific		100.0%
11	908.0000 Customer Assistance Expenses	3,071,080	0	3,071,080	0	3,071,080	0	3,071,080	Specific		100.0%
12	908.0009 Cust Assistance Expense - DSM	67,963,449	(67,963,449)	0	0	0	0	0	Specific		100.0%
13	908.0014 DSM Costs Deferred	3,949,984	(3,949,984)	0	0	0	0	0	Specific		100.0%
14	909-Information & Instruction	0	0	0	0	0	0	0	Specific		100.0%
15	910-Misc Customer Service	292,268	0	292,268	0	292,268	0	292,268	Specific		100.0%
16	Total Customer Service & Information	80,888,992	(71,913,433)	8,975,559	0	8,975,559	0	8,975,559			
17	Sales Expense										
18	911-Supervision	1,783,513	0	1,783,513	0	1,783,513	0	1,783,513	Specific		100.0%
19	912-Demo & Selling	452,861	0	452,861	0	452,861	0	452,861	Specific		100.0%
19	913-Advertising	0	0	0	0	0	0	0	Specific		100.0%
20	916-Misc Sales Expense	0	0	0	0	0	0	0	Specific		100.0%
21	Total Sales Expense	2,236,374	0	2,236,374	0	2,236,374	0	2,236,374			
22	Administrative & General Expense										
23	920-Salaries	28,032,921	0	28,032,921	0	28,032,921	0	28,032,921	Specific		84.7%
24	921-Office Supplies	3,658,638	0	3,658,638	0	3,658,638	0	3,658,638	Specific		91.4%
25	922-Administrative Expense Transferred	(8,846,348)	0	(8,846,348)	0	(8,846,348)	0	(8,846,348)	Specific		99.7%
26	923-Outside Services Employed	6,266,015	0	6,266,015	0	6,266,015	0	6,266,015	Specific		79.2%
27	924-Property Insurance	405,830	0	405,830	0	405,830	0	405,830	Specific		61.0%
28	925-Injuries & Damages	6,195,694	0	6,195,694	0	6,195,694	0	6,195,694	Specific		94.7%
29	926-Employee Pensions and Benefits	13,575,489	0	13,575,489	0	13,575,489	0	13,575,489	Specific		99.8%
30	927-Franchise Requirements	0	0	0	0	0	0	0	Specific		0.0%
31	928-Regulatory Commission Expenses	3,116,403	0	3,116,403	0	3,116,403	0	3,116,403	Specific		99.6%
32	929-Duplicate Charges	0	0	0	0	0	0	0	Specific		0.0%
33	930.1-General Advertising Expense	2,140,085	0	2,140,085	0	2,140,085	0	2,140,085	Specific		99.2%
34	930.2-Misc General Expenses	2,967,260	0	2,967,260	0	2,967,260	0	2,967,260	Specific		70.8%
35	930.2019-gSMART-OvUnd Misc Gen Exp	2,133,288	0	2,133,288	0	2,133,288	0	2,133,288	Specific		100.0%
36	931-Rent	2,143,647	0	2,143,647	0	2,143,647	0	2,143,647	Specific		94.0%
37	Total Admin & General Operation	61,788,920	0	61,788,920	0	61,788,920	0	61,788,920			
38	935-Admin & General Maintenance	13,076,013	0	13,076,013	0	13,076,013	0	13,076,013	Specific		96.1%
39	Total Admin & General Expense	74,864,933	0	74,864,933	0	74,864,933	0	74,864,933			
40	Total Operation & Maint Exp	2,332,870,075	(1,785,364,588)	549,505,487	0	549,505,487	0	549,505,487			

Ohio Power Company - Distribution
Jurisdictional Separation Study
Twelve Months Ended December 31, 2014

Line No.	Description (1)	DISTRIBUTION PER BOOKS (2)	DISTRIBUTION FIXED, KNOWN & MEASURABLE ADJUSTMENTS (3)	DISTRIBUTION AFTER ADJUSTMENT (4)	DISTRIBUTION ADJUSTMENT TO REMOVE PTBAR (5)	DISTRIBUTION AFTER PTBAR ADJUSTMENT (6)	DISTRIBUTION ADJUSTMENT TO REFLECT SFV (7)	DISTRIBUTION AFTER SFV ADJUSTMENT (8)	ALLOCATOR (9)	% (10)
1	4030001 Depreciation Expense									
2	Production	0	0	0	0	0	0	0	N/A	
3	Transmission	0	0	0	0	0	0	0	N/A	
4	Distribution	118,870,055	0	118,870,055	0	118,870,055	0	118,870,055	Direct	
5	General	3,203,481	0	3,203,481	0	3,203,481	0	3,203,481	Direct	
6	Total Depreciation Expense (403)	122,073,535	0	122,073,535	0	122,073,535	0	122,073,535		
7	Amortization Expense									
8	Intangible Plant	15,105,255	0	15,105,255	0	15,105,255	0	15,105,255	Direct	
9	General Plant	146,368	0	146,368	0	146,368	0	146,368	Direct	
10	Total Amortization Expense (404)	15,251,623	0	15,251,623	0	15,251,623	0	15,251,623		
11	Amortization of Plant Acquisition Adjustment	12,696	0	12,696	0	12,696	0	12,696	Specific	100.0%
12	Total Depreciation & Amortization Expense	137,337,855	0	137,337,855	0	137,337,855	0	137,337,855		
13	Reg Debits/Credits Transmission	0	0	0	0	0	0	0	N/A	
14	Reg Debits/Credits Generation	107,272,453	(107,272,453)	0	0	0	0	0	Specific	100.0%
15	Reg Debits/Credits PTBAR	876,914	0	876,914	(876,914)	0	0	0	Specific	100.0%
16	Reg Debits/Credits Storm	2,295,288	0	2,295,288	0	2,295,288	0	2,295,288	Specific	100.0%
17	Reg Debits/Credits DIR	(470,255)	0	(470,255)	0	(470,255)	0	(470,255)	Specific	100.0%
18	Total Reg Debits/Credits (407)	109,974,399	(107,272,453)	2,701,946	(876,914)	1,825,032	0	1,825,032		
1	Other Taxes									
2	Franchise Tax	35,436	0	35,436	0	35,436	0	35,436	Specific	100.3%
3	Commercial Activity Taxes	7,428,608	0	7,428,608	0	7,428,608	0	7,428,608	Specific	99.9%
4	Revenue-KWhr Taxes	146,203,049	0	146,203,049	0	146,203,049	0	146,203,049	Specific	100.0%
5	Payroll Taxes	5,298,864	0	5,298,864	0	5,298,864	0	5,298,864	Specific	104.2%
6	Capacity Taxes	(163,503)	0	(163,503)	0	(163,503)	0	(163,503)	Specific	100.0%
7	Property Taxes	135,389,369	0	135,389,369	0	135,389,369	0	135,389,369	Specific	71.1%
8	Regulatory Fees	4,364,562	0	4,364,562	0	4,364,562	0	4,364,562	Specific	100.0%
9	Production Taxes	2,908	0	2,908	0	2,908	0	2,908	N/A	
10	Miscellaneous Taxes	298,559,293	0	298,559,293	0	298,559,293	0	298,559,293	Specific	100.0%
11	Total Taxes Other Than Income (408.1)	298,559,293	0	298,559,293	0	298,559,293	0	298,559,293		
12	Factoring Expense (4265009 & 4265010)	28,809,064	0	28,809,064	0	28,809,064	0	28,809,064	Specific	100.0%
13	431.0002-Interest on Customer Deposits	1,423,124	0	1,423,124	0	1,423,124	0	1,423,124	Specific	100.0%
14	Total Other	30,232,188	0	30,232,188	0	30,232,188	0	30,232,188		
15	State & Local Income Tax (409.1)	(4,868,952)	325,447	(4,543,505)	(206,620)	(4,750,125)	254,771	(4,495,354)	Direct	
16	Deferred State Income Tax (410.1 & 411.1)	16,658,726	(1,043,781)	15,614,945	(8,532)	15,606,433	0	15,606,433	Direct	
17	Total State Income Taxes	11,789,774	(718,334)	11,071,460	(215,152)	10,856,308	254,771	11,111,079		
18	Current Federal Income Taxes (409.1)	38,407,932	11,592,824	50,000,756	(7,360,067)	42,640,689	9,075,239	51,715,928	Direct	
19	Deferred Federal Income Tax (410.1 & 411.1)	30,761,505	(37,180,042)	(6,418,537)	(303,934)	(6,722,471)	0	(6,722,471)	Direct	
20	Deferred Investment Tax Credit (411.4)	(92,654)	0	(92,654)	0	(92,654)	0	(92,654)	Direct	
21	Total Federal Income Taxes	69,076,784	(25,587,218)	43,489,566	(7,664,001)	35,825,565	9,075,239	44,900,804		

AEP Ohio Straight Fixed Variable Revenue Adjustment Calculation

Rate Zone	Tariff Class	2014 Bill Counts	Straight Fixed-Variable Rate	Straight Fixed Variable Base Revenues	2014 Base Revenues	Revenue Adjustment	PTBAR 2014 Accrual	Difference from PTBAR 2014 Accrual
OP	RS	7,209,954	\$27.24	\$196,399,147	\$178,827,067	\$17,572,080		
OP	RS-TOD	3,768	\$28.09	\$105,843	\$122,906	-\$17,063		
OP	Total Residential	7,213,722		\$196,504,990	\$178,949,974	\$17,555,016	\$7,636,364	\$9,918,652
CSP	R-R	5,987,465	\$27.24	\$163,098,547	\$180,003,053	-\$16,904,506		
CSP	R-R-1	2,072,817	\$27.24	\$56,463,535	\$31,188,212	\$25,275,323		
CSP	RLM	491	\$27.74	\$13,620	\$34,952	-\$21,332		
CSP	RS-TOD	106	\$28.09	\$2,978	\$2,450	\$527		
CSP	RS-TOD2	17,516	\$27.24	\$477,136	\$489,795	-\$12,659		
CSP	RS-CPP	1,972	\$27.24	\$53,717	\$57,643	-\$3,926		
CSP	RS-RTP	95	\$27.24	\$2,588	\$2,848	-\$260		
CSP	Total Residential	8,080,462		\$220,112,120	\$211,778,953	\$8,333,167	\$13,572,227	-\$5,239,060
AEP Ohio	Total Residential	15,294,184		\$416,617,111	\$390,728,927	\$25,888,184	\$21,208,591	\$4,679,593
OP	GS-1	787,383	\$14.81	\$11,661,142	\$11,403,986	\$257,156		
OP	GS-1 On-Peak	95	\$15.66	\$1,488	\$1,674	-\$186		
OP	GS-1 Unmetered	7,771	\$13.26	\$103,043	\$62,521	\$40,522		
OP	Flood Pumps	312	\$14.81	\$4,621	\$9,887	-\$5,266		
OP	Total GS-1	795,561		\$11,770,294	\$11,478,068	\$292,226	\$41,342	\$250,884
CSP	GS-1	624,020	\$14.81	\$9,241,736	\$9,013,538	\$228,198		
CSP	GS-1 Unmetered	7,083	\$13.26	\$93,921	\$318,504	-\$224,583		
CSP	Total GS-1	631,103		\$9,335,657	\$9,332,042	\$3,614	\$222,364	-\$218,750
AEP Ohio	Total GS-1	1,426,664		\$21,105,951	\$20,810,110	\$295,841	\$263,706	\$32,135
AEP Ohio	Total Adjustment			\$437,723,061	\$411,539,037	\$26,184,024	\$21,472,297	\$4,711,727

AEP Ohio Straight Fixed Variable Rate Design

Rate Zone	Tariff Class	11-351 & 11-352 Bill Counts	11-351 & 11-352 Current Base Revenues	11-351 & 11-352 Meter Cost Differential	Revenues from Meter Cost Differential	Revenue Requirement after Meter Differential	Straight Fixed Variable Rate	Verification	Rate Design Difference
OP	RS	7,207,281	\$187,509,197	\$0.00	\$0		\$27.24	\$196,326,334	
OP	RS-TOD	4,902	\$169,213	\$0.85	\$4,167		\$28.09	\$137,697	
OP	Total Residential	7,212,183	\$187,678,410		\$4,167			\$196,464,032	
CSP	R-R	5,627,434	\$188,578,113	\$0.00	\$0		\$27.24	\$153,291,302	
CSP	R-R-1	2,218,108	\$33,867,584	\$0.00	\$0		\$27.24	\$60,421,262	
CSP	RLM	846	\$71,669	\$0.50	\$423		\$27.74	\$23,468	
CSP	RS-ES	24	\$590	\$0.85	\$20		\$28.09	\$674	
CSP	RS-TOD	76	\$1,737	\$0.85	\$65		\$28.09	\$2,135	
CSP	Total Residential	7,846,488	\$222,519,694		\$508			\$213,738,841	
AEP Ohio	Total Residential	15,058,671	\$410,198,104		\$4,675	\$410,193,430		\$410,202,873	-\$4,769
OP	GS-1	778,125	\$11,307,455	\$0.00	\$0		\$14.81	\$11,524,031	
OP	GS-1 On-Peak	263	\$5,452	\$0.85	\$224		\$15.66	\$4,119	
OP	GS-1 Unmetered	8,193	\$67,010	-\$1.55	-\$12,699		\$13.26	\$108,639	
OP	Flood Pumps	312	\$9,262	\$0.00	\$0		\$14.81	\$4,621	
OP	Total GS-1	786,893	\$11,389,179		-\$12,476			\$11,641,410	
CSP	GS-1	614,678	\$9,071,468	\$0.00	\$0		\$14.81	\$9,103,381	
CSP	GS-1 Unmetered	7,319	\$381,610	-\$1.55	-\$11,344		\$13.26	\$97,050	
CSP	Total GS-1	621,997	\$9,453,078		-\$11,344			\$9,200,431	
AEP Ohio	Total GS-1	1,408,890	\$20,842,257		-\$23,820	\$20,866,077		\$20,841,841	\$416

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Case No(s). 11-0351-EL-AIR, 11-0352-EL-AIR, 11-0353-EL-ATA, 11-0354-EL-ATA, 11-0356-EL-AAM, 1

Summary: Correspondence electronically filed by Mr. Matthew J Satterwhite on behalf of Ohio Power Company

OHIO POWER COMPANY
 CLASS COST-OF-SERVICE STUDY - CUSTOMER CHARGE
 TWELVE MONTHS ENDING MAY 31, 2011

Schedule E-3.1
 Page 1 of 6
 Witness Responsible:
 Daniel E. High

Data: 3 MOS Actual & 9 MOS Estimated
 Type of Filing: >Original_Updated_Revised
 Work Paper Reference No(s): WP A-1e-p and all Schedule E3.2 Work Papers

Rate Base Plant In Service	Label	Allocation Factor	Function	Total Retail	RS	GS-1	SEC	PRI	SUB/TRAN	OL	SL
Distribution											
380 Land and Land Rights	DIST_CPD		TOTAL								
361 Structures and Improvements	DIST_CPD		TOTAL								
362 Station Equipment	DIST_CPD		TOTAL								
363 Storage Battery Equipment	DIST_CPD		TOTAL								
364 Poles, Towers & Fixtures	DIST_POLES		TOTAL								
365 Overhead Lines	DIST_OHLINES		TOTAL								
366 Underground Conduit	DIST_UGLINES		TOTAL								
367 Underground Lines	DIST_TRANSF		TOTAL								
368 Transformers	DIST_SERV		TOTAL								
369 Services	DIST_METERS		TOTAL	135,157,954	106,525,465	11,519,258	6,102,533			10,834,152	176,546
370 Meters	DIST_METERS		TOTAL	70,138,185	39,848,665	6,371,020	16,971,615	2,493,786	4,453,099	22,791,009	
371 Install on Cust. Premises	DIST_LO		TOTAL	22,791,009							
372 Leased Prop. On Cust. Premises	DIST_LO		TOTAL	1,104							
373 Street Lighting	DIST_SL		TOTAL	21,232,932							21,232,932
Total	DIST_SL		TOTAL	249,321,184	146,374,130	17,890,278	23,074,148	2,493,786	4,453,099	33,626,265	21,409,478
Total Plant In Service			TOTAL	249,321,184	146,374,130	17,890,278	23,074,148	2,493,786	4,453,099	33,626,265	21,409,478
General Plant	LABOR_M		TOTAL	32,629,865	24,016,177	2,272,437	2,128,672	167,732	839,436	2,296,861	908,531
Intangible Plant	LABOR_M		TOTAL	7,482,064	5,506,936	521,072	488,107	38,461	182,484	526,677	208,327
Total General & Intangible Plant			TOTAL	40,111,930	29,523,113	2,793,509	2,616,779	206,194	1,031,919	2,823,558	1,116,858
Total Electric Plant In Service			TOTAL	289,433,114	175,897,243	20,683,787	25,690,928	2,699,979	5,485,016	36,449,823	22,526,336
Electric Plant Acquisition Adj. - Account 302	LABOR_M		TOTAL	192,123	141,406	13,380	12,534	985	4,943	13,524	5,349
Electric Utility Plant	LABOR_M		TOTAL	289,625,237	176,038,649	20,697,167	25,703,461	2,700,967	5,489,961	38,463,347	22,531,685
Accum. Depreciation and Amortiz.			TOTAL								
Distribution	RB_GUP_EPIS_D		TOTAL	(81,821,472)	(47,919,201)	(5,856,826)	(7,553,995)	(818,403)	(1,457,832)	(11,008,392)	(7,008,924)
General & Intangible	RB_GUP_EPIS_G		TOTAL	(21,399,669)	(15,750,562)	(1,490,335)	(1,395,050)	(110,004)	(550,528)	(1,506,356)	(895,843)
Total			TOTAL	(103,021,161)	(63,669,763)	(7,347,161)	(8,949,045)	(928,407)	(2,008,361)	(12,514,758)	(7,904,766)
Amortiz. Of Plant Acquisition Adj. - Acct 302	LABOR_M		TOTAL	(160,836)	(118,379)	(11,201)	(10,492)	(827)	(4,138)	(11,522)	(4,478)
Net Electric Plant In Service			TOTAL	166,443,240	112,250,508	13,336,804	16,743,024	1,773,734	3,477,462	23,937,267	14,922,441
Working Capital			TOTAL								
Uncollectibles	RSALE		TOTAL								
Materials & Supplies - Dist	RB_GUP_EPIS_D		TOTAL	1,040,534	610,888	74,665	96,299	10,408	18,585	140,338	89,362
Prepayments - Other (Insurance, etc.)	RB_GUP		TOTAL	293,729	178,533	20,990	26,068	2,739	5,558	36,950	22,851
Other Current Assets	LABOR_M		TOTAL								
Total Working Capital			TOTAL	1,334,263	789,421	85,655	122,367	13,147	24,153	177,318	112,203
Rate Base Offsets			TOTAL								

OHIO POWER COMPANY
 CLASS COST-OF-SERVICE STUDY - CUSTOMER CHARGE
 TWELVE MONTHS ENDING MAY 31, 2011

Schedule E-3.1
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 Daniel E. High

Data: 3 MOS Actual & 9 MOS Estimated
 Type of Filing: >Original_Updated_Revised
 Work Paper Reference No(s): WP A-1a-p and all Schedule E3.2 Work Papers

Label	Allocation Factor	Evolution	Total Retail	RS	GS-1	SEC	PRI	SUB/TRAN	OL	SL
Customer Deposits	CUST_DEP	TOTAL	(26,468,865)	(16,034,032)	(807,800)	(4,982,051)	(919,359)	(3,694,937)	(30,687)	-
Customer Advances	RB_GUP_EPIS_D	TOTAL	20,670,064	15,213,545	1,439,522	1,348,452	106,254	531,758	1,455,007	575,527
Prepayments - Pension	LABOR_M	TOTAL	6,883,525	4,041,253	493,934	637,056	68,851	122,946	928,390	591,086
Deferred Taxes (190.1)	RB_GUP_EPIS_D	TOTAL	(23,822,075)	(13,888,289)	(1,895,024)	(2,188,173)	(238,275)	(421,911)	(3,185,939)	(2,028,453)
Deferred Taxes (281.1)	RB_GUP_EPIS_D	TOTAL	(10,057,800)	(5,904,840)	(721,707)	(930,828)	(100,601)	(179,641)	(1,356,508)	(863,674)
Deferred Taxes (282.1)	RB_GUP_EPIS_D	TOTAL	(173,313)	(101,750)	(12,436)	(16,040)	(1,734)	(3,096)	(23,375)	(14,883)
Deferred Taxes (283.1)	RB_GUP_EPIS_D	TOTAL	(77,000)	(45,208)	(5,525)	(7,126)	(770)	(1,375)	(10,385)	(6,612)
Deferred Investment Tax Credits (255)	RB_GUP_EPIS_D	TOTAL	(32,845,463)	(16,699,329)	(1,308,037)	(6,136,710)	(1,083,634)	(3,646,256)	(2,223,498)	(1,746,999)
Total		TOTAL	154,832,039	96,340,599	12,125,422	10,728,681	703,246	(144,841)	21,881,088	13,287,645
Total Rate Base		TOTAL	95,291,817	54,775,152	5,614,278	5,057,830	480,138	21,095,729	4,767,475	3,521,221
Operating Revenues	RSale	TOTAL	207,781	11,692	145,969	54,849	2,403	(7,165)	31	1
Firm Sales of Electricity	MISC_SERV_REV	TOTAL	437,206	396,945	28,675	4,214	15	20	5,926	1,412
Other Operating Revenues	RB_GUP_EPIS_D	TOTAL	603,247	354,161	43,287	55,829	8,034	10,775	81,361	51,801
Forfeited Discounts	RB_GUP_EPIS_D	TOTAL	1,110,885	852,248	79,720	102,819	11,112	19,843	149,840	85,402
Miscellaneous Service Revenue	RB_GUP_EPIS_D	TOTAL	10,347	6,075	742	958	103	185	1,386	889
Rent Assoc Co	RB_GUP_EPIS_D	TOTAL	363,012	213,121	26,048	33,596	3,631	6,484	46,990	31,172
Rent Non-Assoc Co	RB_GUP_EPIS_D	TOTAL	239,347	140,516	17,175	22,151	2,384	4,275	32,281	20,553
Other Electric Revenue-NonAff	RB_GUP_EPIS_D	TOTAL	128,162	75,254	9,198	11,863	1,282	2,289	17,288	11,007
Other Electric Revenue - ABD	RB_GUP_EPIS_D	TOTAL	3,100,108	1,850,015	350,814	286,279	26,974	36,706	337,582	212,237
Other Electric Rev. - PJM Trans Dist/Meter		TOTAL	98,391,925	56,625,167	5,985,090	5,344,108	487,112	21,132,435	5,104,557	3,733,458
Total - Other Operating Revenues		TOTAL	686,102	397,903	52,314	88,949	11,244	20,056	66,634	59,002
Operating Expenses	TOTXEXP	TOTAL	-	-	-	-	-	-	-	-
O&M Expense	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
Distribution Operation	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
590 Supervision & Engineering	DIST_OHNLINES	TOTAL	-	-	-	-	-	-	-	-
591 Load Dispatching	DIST_UGLINES	TOTAL	-	-	-	-	-	-	-	-
592 Station Equipment	DIST_SL	TOTAL	130,576	-	-	-	-	-	-	130,576
593 Overhead Lines	DIST_METERS	TOTAL	1,355,619	770,188	123,138	328,025	48,199	86,069	-	-
594 Underground Lines	DIST_PCUST	TOTAL	104,068	81,949	8,862	4,695	92	-	8,335	136
595 Street Lighting	RB_GUP_EPIS_D	TOTAL	3,198,173	1,877,817	229,488	295,984	31,989	57,122	431,342	274,831
596 Meters	RB_GUP_EPIS_D	TOTAL	477,801	280,395	34,271	44,201	4,777	6,530	64,415	41,012
597 Customer Installations	RB_GUP_EPIS_D	TOTAL	5,962,139	3,408,053	448,073	761,854	96,301	171,777	570,725	505,357
598 Miscellaneous Distribution		TOTAL	32,066	3,503	560	1,492	219	391	21,879	4,021
599 Rents	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
Total	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
Distribution Maintenance	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
590 Supervision & Engineering	TOTXEXP	TOTAL	-	-	-	-	-	-	-	-
591 Structures	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
592 Station Equipment	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
593 Overhead Lines	TOTXEXP	TOTAL	-	-	-	-	-	-	-	-
594 Underground Lines	TOTXEXP	TOTAL	-	-	-	-	-	-	-	-

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Label	Allocation Factor	Function	Total Retail	RS	GS-1	SEC	PRI	SUBTRAN	OL	SL
595 Line Transformers	DIST_TRANSF	TOTAL	291,693	-	-	-	-	-	-	291,693
596 Street Lighting	DIST_SL	TOTAL	447,288	-	-	-	-	-	-	-
597 Meters	DIST_METERS	TOTAL	1,587,332	264,130	40,630	108,234	15,904	28,399	1,587,332	-
598 Miscellaneous Distribution	DIST_OL	TOTAL	2,358,368	257,633	41,190	109,728	16,123	28,791	1,609,211	295,714
Total										
Customer Accounts	TOTOX234	TOTAL	1,236,517	1,080,747	94,360	58,685	1,242	309	43	1,131
901 Supervision & Engineering	CUST_902	TOTAL	4,971,654	4,119,497	445,467	394,262	9,820	2,609	-	-
902 Meter Reading	CUST_903	TOTAL	19,708,498	17,453,402	1,437,934	776,771	14,911	3,442	-	22,038
903 Customer Records & Collection Exp.	UNCOLFAC	TOTAL	6,342	3,723	455	587	63	113	855	545
904 Uncollectible Accounts	RSAL	TOTAL	3,007,437	1,728,719	177,188	159,627	14,522	865,787	150,483	111,131
Factoring Expense	CUST_DEP	TOTAL	793,231	480,515	24,209	149,304	27,552	110,732	920	-
431-Interest on Customer Deposits	TOTOX234	TOTAL	73,207	63,985	5,587	3,474	74	18	3	67
905 Miscellaneous Customer Accounts		TOTAL	28,796,885	24,930,589	2,185,199	1,542,710	88,184	783,010	152,283	134,811
Total										
Customer Service & Inf & Sales Exp	EXP_OM_CUSTACCT	TOTAL	1,074,267	898,822	78,783	55,819	2,458	28,230	5,490	4,864
907 Supervision	EXP_OM_CUSTACCT	TOTAL	1,287,487	1,077,221	94,420	66,659	2,946	33,833	6,590	5,829
908 Customer Assistance	EXP_OM_CUSTACCT	TOTAL	286,981	247,851	21,707	15,325	677	7,778	1,513	1,340
909 Information & Instruction	EXP_OM_CUSTACCT	TOTAL	1,778	1,486	130	92	4	47	8	8
910 Miscellaneous Customer Service	EXP_OM_CUSTACCT	TOTAL	9,607	8,038	705	497	22	252	48	43
911-916 Misc Selling Expense	EXP_OM_CUSTACCT	TOTAL	2,668,128	2,233,218	195,744	138,192	6,108	70,140	13,841	12,095
Total										
Administrative & General Expense	LABOR_M	TOTAL	2,459,015	1,809,880	171,253	180,419	12,640	53,261	173,095	88,468
920-Salaries	LABOR_M	TOTAL	246,061	181,098	17,136	16,052	1,265	6,330	17,320	6,851
921-Office Supplies	LABOR_M	TOTAL	(973,028)	(716,165)	(67,764)	(63,477)	(5,002)	(25,032)	(68,493)	(27,082)
922-Admin Exp Transferred	LABOR_M	TOTAL	375,253	276,193	26,480	24,480	1,929	9,654	26,415	10,448
923.0001 Outside Svcs Empl - Non-Assoc.	LABOR_M	TOTAL	2,480,673	1,825,820	172,761	161,831	12,752	63,818	174,619	89,071
923.0003 AEPSC Billed to Client Co.	RB_GUP_EPIS_D	TOTAL	40,027	23,500	2,872	3,704	400	715	5,399	3,437
924-Property Insurance	LABOR_M	TOTAL	592,185	435,859	41,241	38,632	3,044	15,235	41,685	16,489
925-Injuries & Damages	LABOR_M	TOTAL	2,114,752	1,558,498	147,277	137,980	10,871	54,404	148,862	58,882
926.0003 Pension Plan	LABOR_M	TOTAL	648,112	477,022	45,138	42,281	3,332	16,673	45,622	18,045
927-Franchise Requirements	RSAL	TOTAL	28,347	16,294	1,670	1,505	137	6,275	1,416	1,047
928.0000 Reg. Commission Exp.	RSAL	TOTAL	-	-	-	-	-	-	-	-
929 Duplicate Charges	LABOR_M	TOTAL	278,555	205,021	19,399	18,172	1,432	7,188	19,608	7,756
930.1 Gen. Advertising Exp.	LABOR_M	TOTAL	629,754	463,511	43,858	41,083	3,237	16,201	44,330	17,535
930.2000 Misc. General Expenses	LABOR_M	TOTAL	71,052	41,714	5,098	6,578	711	1,269	9,593	6,101
930.2007 ABD Exp.	RB_GUP_EPIS_D	TOTAL	337,341	248,289	23,483	22,007	1,734	8,678	23,746	9,393
931 Rent	LABOR_M	TOTAL	1,258,111	925,992	87,618	82,075	6,467	32,366	88,561	35,030
935 A&G - Maintenance	LABOR_M	TOTAL	10,586,202	7,770,525	737,184	693,300	54,849	277,013	751,769	301,481
Total										
Total O&M Expense		TOTAL	51,372,743	38,600,018	3,607,390	3,246,782	241,665	1,330,730	3,037,630	1,249,528
Depreciation & Amortization Expense	RB_GUP_EPIS_D	TOTAL	9,294,156	5,456,512	666,911	860,154	92,803	186,002	1,253,515	798,089
Distribution	RB_GUP_EPIS_G	TOTAL	1,890,244	1,391,254	131,642	123,314	9,717	48,628	133,058	52,631
General & Intangible		TOTAL	11,184,400	6,847,766	798,553	983,468	102,680	214,630	1,386,573	850,730
Total Depreciation & Amort Expense										

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Label	Allocation Factor	Function	Total Retail	RS	GS-1	SEC	PRI	SUB/TRAN	OL	SL
Taxes Other Than Income										
Payroll Taxes	LABOR_M	TOTAL	732,811	639,382	51,035	47,808	3,787	18,852	51,584	20,404
Commercial Activity Taxes	RSALE	TOTAL	1,314,864	755,803	77,487	69,789	6,348	281,085	85,783	48,587
Property Taxes	NP	TOTAL	8,960,288	5,384,855	641,051	804,654	85,244	187,124	1,150,403	717,159
Regulatory Fees	RSALE	TOTAL	816,882	489,556	48,128	43,358	3,944	180,841	40,869	30,185
Franchise Tax	NP	TOTAL	36,330	22,033	2,258	185	1,918	6,486	1,416	1,416
Miscellaneous Taxes	NP	TOTAL	(1,183)	(712)	(85)	(106)	(11)	(22)	(152)	(85)
Total Taxes Other Than Income		TOTAL	11,861,992	7,180,696	818,855	967,636	99,478	868,366	1,910,404	817,657
Total Operating Expense Before Income Tax		TOTAL	74,419,138	52,628,481	5,225,787	5,196,757	443,823	2,211,726	5,794,607	2,917,914
Gross Operating Income		TOTAL	23,972,790	3,996,666	739,293	147,322	43,289	18,920,709	(690,050)	815,544
Interest Expense Factor		TOTAL	3,752,764	2,353,562	293,702	259,870	17,034	(3,504)	530,246	321,853
Interest Expense Synchronized		TOTAL	20,220,026	1,663,124	445,591	(112,548)	28,255	18,924,212	(1,220,286)	483,690
Net Operating Income Before Income Tax		TOTAL	(3,957,600)	(2,471,255)	(233,833)	(219,040)	(17,260)	(86,378)	(235,348)	(93,487)
Schedule M Income Adjustments		TOTAL	(50,806)	(31,592)	(3,976)	(3,518)	(231)	47	(7,179)	(4,357)
Labor Related	LABOR_M	TOTAL	(5,584,448)	(3,278,577)	(400,717)	(516,828)	(55,857)	(99,743)	(753,182)	(479,543)
Rate Base Related	RATEBASE	TOTAL	35,706	20,963	2,582	3,305	357	638	4,816	3,068
Distribution Plant Related	RB_GUP_EPIS_D	TOTAL	(8,957,148)	(5,780,462)	(635,984)	(736,082)	(72,980)	(185,436)	(991,883)	(574,321)
General Plant Related	RB_GUP_EPIS_D	TOTAL	1,932,755	1,134,702	138,687	178,872	19,332	34,521	260,673	165,968
State Tax Adjustments		TOTAL	2,339,352	1,373,411	167,862	216,502	23,399	41,783	315,511	200,863
Illinois - Plant Related	RB_GUP_EPIS_D	TOTAL	678,014	398,058	48,652	62,749	6,732	12,110	81,445	58,222
Michigan - Plant Related	RB_GUP_EPIS_D	TOTAL	13,195,633	(2,962,635)	(51,687)	(659,757)	(27,403)	18,773,297	(1,951,515)	85,337
Ohio - Plant Related	RB_GUP_EPIS_D	TOTAL	7,694	(1,727)	(30)	(381)	(16)	10,846	(1,138)	50
West Virginia - Plant Related	RB_GUP_EPIS_D	TOTAL	13,802,229	(2,725,926)	(22,511)	(632,128)	(23,337)	18,780,559	(1,896,677)	120,252
Illinois Taxable Income		TOTAL	4,167	(834)	(7)	(194)	(7)	5,753	(581)	37
Tax Factor (Tax Rate x Apportionment)		TOTAL	11,940,892	(3,699,262)	(141,722)	(795,881)	(39,954)	16,750,887	(2,120,744)	(22,409)
Illinois Tax		TOTAL	42,049	(13,027)	(498)	(2,767)	(141)	66,030	(7,468)	(79)
Michigan Taxable Income		TOTAL	11,262,878	(4,097,338)	(190,373)	(848,630)	(46,735)	18,738,777	(2,212,188)	(80,631)
Tax Factor (Tax Rate x Apportionment)		TOTAL	148,546	(54,040)	(2,511)	(11,193)	(816)	247,146	(29,177)	(1,083)
Michigan Tax		TOTAL								
Ohio Municipal Taxable Income		TOTAL								
Tax Factor (Tax Rate x Apportionment)		TOTAL								
Ohio Tax		TOTAL								
West Virginia Taxable Income		TOTAL								
Tax Factor (Tax Rate x Apportionment)		TOTAL								
West Virginia Tax		TOTAL								

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Label	Allocation Factor	Function	Total Retail	RS	GS-1	SEC	PRI	SUBTRAN	DL	SL
Deferred State Income Tax (410.1 & 411.1)	RB_GUP_EPIS_D	TOTAL	19,054	11,187	1,367	1,753	191	340	2,570	1,636
Total State Income Tax		TOTAL	221,510	(58,442)	(1,680)	(12,781)	(590)	330,215	(35,794)	580
Federal Taxable Income		TOTAL	11,080,422	(4,027,708)	(187,326)	(834,086)	(45,955)	18,408,802	(2,173,825)	(79,575)
Tax Factor (Tax Rate x Apportionment)		TOTAL	3,871,148	(1,409,688)	(65,564)	(291,930)	(18,084)	6,443,118	(760,839)	(27,851)
Gross Current FIT		TOTAL	2,491,005	1,462,446	178,744	230,537	24,916	44,492	335,965	213,905
Deferred FIT		TOTAL	-	-	-	-	-	-	-	-
Deferred ITC		TOTAL	-	-	-	-	-	-	-	-
Investment Tax Credit (411.4 & 411.5)	RB_GUP_EPIS_D	TOTAL	6,362,153	52,748	113,180	(61,393)	8,831	6,487,607	(424,874)	166,054
Total Federal Income Tax		TOTAL	6,563,663	(5,694)	111,501	(74,173)	8,242	6,817,822	(460,667)	186,634
Total Income Tax		TOTAL	81,002,798	52,622,787	5,337,298	5,122,813	452,065	9,029,549	5,333,840	3,104,549
Total Expenses		TOTAL	17,389,127	4,002,380	827,792	221,486	35,047	12,102,888	(229,383)	628,809
Net Operating Income		TOTAL	4,72%	4.15%	5.18%	2.16%	4.14%	-8367.52%	-1.05%	4.73%
Current Rate of Return		TOTAL	3,887,413	1,703,825	227,411	405,114	62,255	93,225	1,013,243	372,341
O&M Labor		TOTAL	9,191,787	7,690,625	674,093	475,897	21,034	241,544	46,977	41,818
Distribution	EXP_OM_DIST	TOTAL	2,159,217	1,808,583	158,349	111,792	4,841	56,740	11,086	9,776
Customer Accounts	EXP_OM_CUSTACCT	TOTAL	15,218,417	11,201,033	1,059,854	982,803	78,230	391,509	1,071,254	423,734
Customer Service	EXP_OM_CUSTSERV	TOTAL	13,063,936	8,123,481	1,022,421	904,647	59,296	(12,196)	1,845,866	1,120,420
Total		TOTAL	8,43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%
Proposed Operating Income (NOI + Inc. Defic.)	RATEBASE	TOTAL	(4,325,191)	4,121,100	394,828	683,151	24,251	(12,115,083)	2,075,248	481,511
Proposed Rate of Return		TOTAL	(6,818,594)	6,486,848	622,125	1,076,977	38,231	(19,099,233)	3,271,596	774,859
Income Increase		TOTAL	68,531	62,220	4,495	860	2	3	929	221
Gross Revenue Conversion Factor	MISC_SERV_REV	TOTAL	196,630	145,440	14,109	18,198	1,967	3,512	28,520	16,885
Total Revenue Increase	RB_GUP_EPIS_D	TOTAL	(7,083,755)	8,319,189	603,521	1,058,118	36,262	(19,102,748)	3,244,147	757,752
Less: Miscellaneous Service Charge Increases		TOTAL	88,208,063	61,094,341	6,217,798	6,115,948	495,400	1,992,881	6,011,622	4,278,974
Less: Pole Attachment Increases		TOTAL								
Proposed Sales Revenue Increase		TOTAL								
Total Proposed Sales Revenue		TOTAL								

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Customer Bills				7,212,183	786,893	423,484	8,142	1,816		
Full Cost Customer Charge				8.47	7.90	14.44	80.97	1,040.18		

Source: WP A-1e-p and all Schedule E-3.2 Work Papers
Date Prepared: 2/28/2011

**OHIO POWER COMPANY'S RESPONSE
TO NATURAL RESOURCES DEFENSE COUNCIL'S
DISCOVERY REQUEST
PUCO CASE NO. 16-1852-EL-SSO
FIRST SET**

INTERROGATORY

- NRDC-INT-1-001 On page 13, lines 3-4, of Witness Moore's Direct Testimony, Witness Moore states, "that a full customer charge should be \$27.24 for a standard residential customer." Please answer the following questions regarding that statement.
- A. Please explain whether the stated charge is based on embedded or marginal cost principles.
- B. Please disaggregate the "full customer charge" in the greatest detail available, including, at a minimum, the following: the meter cost, meter-reading cost, billing, service drop, customer service, and any other identifiable cost components.
- C. Please explain whether the estimate of customer costs included in the \$27.24 is based on the smallest residential customer, the average single-family residential customer, the average multi-family residential customer, the average residential customer, or some other customer group.
- D. Please explain whether the estimate of service-drop costs included in the \$27.24 estimate of customer costs assumes that the customer has a dedicated service drop, or is in a multi-family building that shares a service drop among several customers.

RESPONSE

- A. The \$27.24 full customer charge identified in Company witness Moore's testimony reflects the embedded costs of serving AEP Ohio residential customers.
- B. See NRDC-RPD-1-001 Attachment 1.
- C. The \$27.24 represents the average base revenue per residential bill. The residential base revenues that support the \$27.24 were presented in the presented in Column K of Schedule E-4.1 in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR and were calculated using base rates at the time of that filing. The total number of residential bills issued during the test period are presented in Column C of the same schedules.
- D. The Company does not allocate service drop assets, included in FERC Account 369 Services, to a level lower than the customer classes identified in Class Cost-of-Service Studies developed by Company witness High in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR.

Prepared by: Andrea E. Moore

**OHIO POWER COMPANY'S RESPONSE
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PUCO CASE NO. 16-1852-EL-SSO
FIRST SET**

INTERROGATORY

NRDC-INT-1-014 On page 14, lines 10-11, of her Direct Testimony, Witness Moore states, "with the proposed increase in the customer charge more accurately reflecting the cost causation from customers' use of the distribution system." Please explain how the proposed increase more accurately reflects the cost causation from the customers' use of the distribution system. Specifically, please list the components of the distribution system for which the Company believes that cost causation is more accurately reflected by including the cost in a customer charge, rather than in an energy charge.

RESPONSE

The cost of providing distribution service do not vary with volumetric usage. Generally, the distribution system costs are affected by either peak demand imposed on the distribution facilities or by the number of customers served. If these costs are primarily recovered through an energy charge, the customer is sent a price signal that by lowering their usage they are lowering the cost imposed on the system even though they have not necessarily lowered the costs imposed on the system.

Prepared by: Selwyn J. Dias
 Andrea E. Moore

**OHIO POWER COMPANY'S RESPONSE
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INTERROGATORY

NRDC-INT-1-005 Please indicate the percentage of poles that would have been avoided if half the residential customers along an overhead primary feeder (e.g., every second customer) had never existed.

RESPONSE

The Company objects because it is unable to fully answer the hypothetical question posed in the absence of all of the pertinent assumptions and fact/circumstances that apply to the hypothetical scenario. Without waiving the foregoing objection(s) or any general objection the Company may have, the Company states as follows. The Company has not performed the requested analysis.

Prepared by: Counsel

Marginal Elasticity Sources

Authors	Date	Title	Link
Acton, Bridger, and Mowill	1976	Residential Demand for Electricity in Los Angeles- an Econometric Study of Disaggregated Data	http://www.rand.org/pubs/reports/R1899.html
McFadden, Puig, and Kirshner	1977	Determinants of Long-Run Demand for Electricity	http://eml.berkeley.edu/reprints/mcfadden/7_2.pdf
Barnes, Gillingham, and Hageman	1981	The Short-Run Residential Demand for Electricity	www.jstor.org/stable/1935850
Henson	1984	Electricity Demand Estimates under Increasing- Block Rates	www.arlis.org/docs/vol2/hydropower/APA_DOC_no._3448.pdf
Reiss and White	2001	Household Electricity Demand, Revisited	www.nber.org/papers/w8687.pdf
Xcel Energy Colorado	2012	Impact Analysis of Residential Two Tier, Inverted Block Rates	Attached
Orans et al,	2014	Are Residential Customers Price-Responsive to an Inclining Block Rate? Evidence from British Columbia	http://docslide.us/documents/are-residential-customers-price-responsive-to-an-inclining-block-rate-evidence.html



Impact Analysis of Residential Two Tier, Inverted Block Rates (IBR)

01/22/2013

PROCEDURAL HISTORY

- As a result of its generic investigation into customer incentives launched in 2008, the Commission directed the Company to file options for residential tiered (inverted block) rates in our next Phase II (rate design) filing.
- (For purposes of this presentation, I'm using the terms inverted block rates and tiered rates interchangeably.)
- In response to this directive, in May 2009 the Company filed for approval of a residential tiered rate structure that would:
 - ◆ be limited to the 4 summer months; and
 - ◆ have two summers tiers, with a rate of 5.1 cents per kWh applied to the first 500 kWh in a billing period, and a rate of 8 cents per kWh applied to all additional use.
- In 2010 the CPUC approved the Company's proposal with one modification: the first tier rate was set at 4.6 cents per kWh, and the second tier rate was set at 9 cents per kWh.
- These tiered rates were first implemented in the summer of 2010.

Purpose of Tiered Rates

- The primary purpose of the approved tiered rate structure was to encourage a more efficient use of energy during the summer, since summer peak loads drive the Company's generation and transmission capacity costs.
- These price signals could be provided without the higher metering costs associated with time-of-use rates and applied to all residential customers.
- The idea was that customers would respond to the higher price applied to their use above 500 kWh by reducing their energy use.
- The Company set its rates assuming that customers would reduce their summer energy use by 0.26% for each 1.0 % increase in the marginal price attributable to tiered rates.
- We also assumed that usage in all other months would decrease by 0.13% for each 1.0% decline in those rates.
- Elasticity estimates were based on an assumed customer response to their total kWh Rate.
- We always planned to “re-estimate” customer response based on actual data, particularly in the summer.

High-Level Approach to Estimating IBR Impact

- Accumulate multiple years of data to:
 - ◆ mitigate impacts of anomalies in data or customer response in any one year; and
 - ◆ test for any differences between short- and long-run impacts.
- Limit analysis to summer months.
- For each year analyzed, “back into” IBR impact by stripping away changes in residential use attributable to factors other than IBR rates.
- Compare estimated response based on actual data with assumed response at time IBR rates were approved – requires normalization of data to compare fairly the test year with the years for which we’re measuring a response.

Caveats With Analysis

- Not easy to estimate or measure impact of a price signal – a lot of unknowns with regard to customer behavior:
 - ◆ Level of customer knowledge
 - ◆ Customer perceptions of their cost
 - ◆ Other influences on customer usage
 - ◆ Consistency in data from year to year

Steps Taken to Estimate IBR Impact

- Obtained actual raw usage data from Company records.
- **ADJUSTED DATA TO TEST YEAR CONDITIONS:**
- Adjusted usage for billing administrative differences.
- Normalized usage for weather consistent with Test Year weather normalization approach.
- Adjusted usage for economic conditions that were different from the Test Year economic conditions.
- **CONCLUSION:**
IBR Impact is the resulting difference from the estimated 2010 Test Year Usage Per Customer before IBR impacts taken into account.

Adjustments to Residential Usage per Customer to Capture Differences from Test Year Conditions

- **Billing Administrative Differences from Test Year: actual usage adjusted to reflect billing changes from Test Year:**
 - ◆ May usage billed in June
 - ◆ Billing cycles per month
 - ◆ Average billing days per month
- **Weather: Actual usage normalized assuming test-year weather**
- **Economic Conditions: Actual usage adjusted to net out usage impacts attributable to economic drivers:**
 - ◆ Number of Customers
 - ◆ Base Economic Conditions
 - ◆ Demand Side Management (DSM) Impacts
 - ◆ Solar Rewards Impacts

Actual Unadjusted Residential Summer Monthly Usage Per Customer (kWh)

2010	◆ 714.6
2011	◆ 708.6
2012	◆ 761.6

Adjusted Summer Monthly Residential Usage Per Customer (kWh)

Test Year Forecast After IBR Impact

◆ 661.6

Actual Adjusted

2010

◆ 674.2

2011

◆ 656.8

2012

◆ 659.3

Resulting Estimate of IBR Impact on Summer Monthly Usage Per Customer (kWh)

2010 Test Year Estimate

◆ (25.1)

2010 Estimated Actual

◆ (12.5)

2011 Estimated Actual

◆ (29.9)

2012 Estimated Actual

◆ (27.4)

Comparison of IBR % Impact on Usage

2010 Prediction (Test Year)

■ (3.65)%

2010 Actual

■ (1.89)%

2011 Actual

■ (4.36)%

2012 Actual

■ (3.99)%

Approach for Estimating IBR Impact on System Peak

- Assumed a constant residential load factor.
- Assumed the impact of weather was uniform.
- Assumed annual system peak occurred in the summer months.
- Assumed a 75% coincidence between consumption change and change in peak demand.

Estimate of IBR Impact on System Peak

2010 Prediction

■ (2.7)%

2010 Actual

■ (1.4)%

2011 Actual

■ (3.3)%

2012 Actual

■ (2.9)%

SUMMARY OF IMPACTS

Month	Actual Unadjusted Usage Per Customer	Actual Adjusted or Estimated Energy Consumption Per Customer After IBR (kWh/month)	Adjusted Energy Consumption Per Customer Minus Test Year Unadjusted Consumption Per kWh (kWh/month)	Change in Energy Consumption (%)	% Change in Class Coincident Peak
2010 TEST YEAR					
Summer Months	686.7	661.6	(25.1)	-3.65%	-2.7%
ACTUAL 2010					
Summer Months	714.6	674.2	(12.5)	-1.89%	-1.4%
ACTUAL 2011					
Summer Months	708.6	656.8	(29.9)	-4.35%	-3.3%
ACTUAL 2012					
Summer Months	761.6	659.3	(27.4)	-3.99%	-2.9%

CONCLUSIONS FROM ANALYSIS

- **Inverted Block Rates did lower residential summer usage by some amount.**
- **Average of customer responses during 2010, 2011 and 2012 similar to response predicted.**
- **Response in second and third years greater than response in first year.**
- **Despite level of uncertainty with estimated customer response, the results are based on analysis of entire population of residential customers – not a sample.**

**OHIO POWER COMPANY'S RESPONSE
TO NATURAL RESOURCES DEFENSE COUNCIL'S
DISCOVERY REQUEST
PUCO CASE NO. 16-1852-EL-SSO
FIRST SET**

REQUEST FOR PRODUCTION OF DOCUMENTS

NRDC-RPD-1-027 Please provide any studies or documents available to the Company that estimate the extent to which a decrease in energy charges will increase energy usage by customers.

RESPONSE

The Company has not performed the requested analysis.

Prepared by: Andrea E. Moore

**OHIO POWER COMPANY'S RESPONSE
TO NATURAL RESOURCES DEFENSE COUNCIL'S
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PUCO CASE NO. 16-1852-EL-SSO
FIRST SET**

REQUEST FOR PRODUCTION OF DOCUMENTS

NRDC-RPD-1-012 Please provide the number of residential customers served by the Company, by county.

RESPONSE

See NRDC-RPD-1-012 Attachment 1 for the number of residential customers by county

Prepared by: Andrea E. Moore

Ohio Power Company
Columbus Southern Power Rate Zone
Residential Secondary Bundled Service
Breakdown of Charges Based on Entered Information

Billing Parameters

Metered kWh Usage: 1,000 kWh

	Rates			Billing		
	Generation	Transmission	Distribution	Generation	Transmission	Distribution
Customer Charge			8.40			8.40
Energy Charge			\$ 0.0182747			\$ 18.27
Base Charges						\$ 26.67
Total						\$ 44.74

	Generation	Transmission	Distribution	Total	kWh
1,000 kWh	\$ 0.0001430	\$ 0.0001430	\$ 0.0001430	\$ 0.000430	1,000
0 kWh	\$ 0.0001430	\$ 0.0001430	\$ 0.0001430	\$ 0.000430	0
1,000 kWh	\$ 0.00465	\$ 0.00465	\$ 0.00465	\$ 0.01395	1,000
0 kWh	\$ 0.00419	\$ 0.00419	\$ 0.00419	\$ 0.01257	0
0 kWh	\$ 0.00363	\$ 0.00363	\$ 0.00363	\$ 0.01098	0
\$26.67 Base (Dist)	\$ -3.5807%	\$ -3.5807%	\$ -3.5807%	\$ -0.127	1,000
1,000 kWh	\$ 0.0016693	\$ 0.0016693	\$ 0.0016693	\$ 0.00500	1,000
\$26.67 Base (Dist)	\$ 7.7300%	\$ 7.7300%	\$ 7.7300%	\$ 2.06	1,000
1,000 kWh	\$ 0.0466600	\$ 0.0466600	\$ 0.0466600	\$ 0.14	1,000
1,000 kWh	\$ 0.0102700	\$ 0.0102700	\$ 0.0102700	\$ 0.03	1,000
1,000 kWh	\$ (0.0010714)	\$ (0.0010714)	\$ (0.0010714)	\$ (0.0032)	1,000
1,000 kWh	\$ 0.0016624	\$ 0.0016624	\$ 0.0016624	\$ 0.0050	1,000
1,000 kWh	\$ 0.0142293	\$ 0.0142293	\$ 0.0142293	\$ 0.0427	1,000
\$26.67 Base (Dist)	\$ 0.0031170	\$ 0.0031170	\$ 0.0031170	\$ 0.0093	1,000
\$26.67 Base (Dist)	\$ 1.05864%	\$ 1.05864%	\$ 1.05864%	\$ 0.28	1,000
Month	\$ 7.34119%	\$ 7.34119%	\$ 7.34119%	\$ 2.16	1,000
1,000 kWh	\$ 1.01	\$ 1.01	\$ 1.01	\$ 3.12	1,000
\$26.67 Base (Dist)	\$ 0.0015421	\$ 0.0015421	\$ 0.0015421	\$ 0.0046	1,000
1,000 kWh	\$ 28.98750%	\$ 28.98750%	\$ 28.98750%	\$ 7.73	1,000
\$26.67 Base (Dist)	\$ 0.0010060	\$ 0.0010060	\$ 0.0010060	\$ 0.0030	1,000
Riders Total					
Base + Rider Total					

	Current	Proposed
Total per-kWh charges	\$ 109.74	\$ 96.02
Total bill	\$ 122.64	\$ 122.94

**OHIO POWER COMPANY'S RESPONSE
TO NATURAL RESOURCES DEFENSE COUNCIL'S
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PUCO CASE NO. 16-1852-EL-SSO
FIRST SET**

INTERROGATORY

NRDC-INT-1-013 Please explain whether the higher proposed customer charge (\$18.40 by January 1, 2018, as described on pages 12 to 13 of Witness Moore's Direct Testimony) may encourage some customers who are eligible for the Percentage of Income Payment Plan and have consumption below the average residential usage to file for the Percentage of Income Payment Plan. If not, please explain why.

RESPONSE

As a premise for the question, the Company cannot verify that there are any PIPP eligible customers that are not already participating in the program. Further, the Company has not performed any studies that would indicate whether or not the higher proposed customer charge would encourage customers that are already eligible to participate in the PIPP plan (but chose not to participate to date) would begin participating if their usage was below the average usage.

Prepared by: Selwyn J. Dias
 Andrea E. Moore

**OHIO POWER COMPANY'S RESPONSE
TO NATURAL RESOURCES DEFENSE COUNCIL'S
DISCOVERY REQUEST
PUCO CASE NO. 16-1852-EL-SSO
FIRST SET**

REQUEST FOR PRODUCTION OF DOCUMENTS

NRDC-RPD-1-028 Please provide any data on the bill frequency distribution of the Company's low-income residential customers, other than those on the Percentage of Income Payment Plan.

RESPONSE

The Company has not performed the requested analysis.

Prepared by: Andrea E. Moore

**OHIO POWER COMPANY'S RESPONSE
TO NATURAL RESOURCES DEFENSE COUNCIL'S
DISCOVERY REQUEST
PUCO CASE NO. 16-1852-EL-SSO
FIRST SET**

INTERROGATORY

- NRDC-INT-1-010 On page 13, lines 7-10, of Witness Moore's Direct Testimony, Witness Moore states, "Distribution costs are incurred by sizing the distribution system to meet customer(s) peak kW demand usage. These costs vary by peak demand requirements, not by kWh usage or by simply connecting a customer to the system. These costs would ideally be collected through a demand charge..." Please answer the following questions regarding that statement:
- A. Please explain what portion of the proposed residential customer charges would include collection of these demand-related costs.
 - B. Please explain whether Witness Moore's reference to "customer(s) peak kW demand usage" means one of the following:
 - i. each customer's maximum monthly demand, whenever it occurs;
 - ii. each customer's maximum annual demand, whenever it occurs;
 - iii. the customers' collective maximum demand on the particular piece of distribution equipment;
 - iv. or something else.
 - C. If Witness Moore's reference to "customer(s) peak kW demand usage" means each customer's maximum demand, regardless of timing, please explain how this measure of customer load determines the sizing of line transformers, feeders and substations.
 - i. Please provide a breakdown of the Company's annual demand-related distribution costs among the following components: secondary lines, line transformers, primary lines, and distribution substations.
 - ii. For each such component, please provide the Company's estimate of the ratio of total load on the average or typical component to the sum of the maximum demands of the customers served by that component.
 - D. To the extent Witness Moore believes that a residential customer's maximum demand, whenever it occurs, determines the cost of distribution equipment, please explain how that would be the case for:
 - i. The substation;
 - ii. The feeder; and
 - iii. The line transformer.

**OHIO POWER COMPANY'S RESPONSE
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PUCO CASE NO. 16-1852-EL-SSO
FIRST SET**

RESPONSE

A. In the combined rate design proposed by the Company in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR, the Company identified its full cost residential customer charge as \$8.40 per residential customer bill. Any increase above the \$8.40 would recover the Company's demand-related costs.

B. The statement is a general statement representing that the cost of service study in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR provides for the peak demands in allocation of the distribution system. Some equipment is based on the coincident peak of the system while others are a combination of the non-coincident peak as well as the annual non-coincident peak.

C. The secondary distribution system (secondary lines, secondary components of line transformers) are allocated using 50% of the customer's maximum demand and 50% of the annual customers demand. The primary system (primary lines, primary components of the line transformers) as well as substations are allocated based on the peak load.

i. See Schedule E3.2 in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR.

ii. See Schedules WP E-3.2y and WP E 3.2x in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR.

D. See response to C.

Prepared by: Andrea E. Moore

**OHIO POWER COMPANY'S RESPONSE TO
NATURAL RESOURCE DEFENSE COUNCIL'S
DISCOVERY REQUEST
PUCO CASE NO. 16-1852-EL-SSO et al.
SECOND SET**

INTERROGATORY

NRDC-INT-2-017 What is the difference between "non-coincident peak" and "annual non-coincident peak" as used in the Company's response to NRDC INT-1-010 (B)?

RESPONSE

Non-coincident peak was referring to the class maximum demand and annual non-coincident peak was referring to the sum of the individual customer maximum demand.

Prepared by: Andrea E. Moore

**OHIO POWER COMPANY'S RESPONSE TO
NATURAL RESOURCE DEFENSE COUNCIL'S
DISCOVERY REQUEST
PUCO CASE NO. 16-1852-EL-SSO et al.
SECOND SET**

INTERROGATORY

- NRDC-INT-2-019 The Company's response to NRDC INT-1-010(C) states, "The primary system (primary lines, primary components of the line transformers) as well as substations are allocated based on the peak load." Please answer the following questions regarding that statement:
- A. What "peak load" is being referred to in that response?
 - B. Is it contribution to the AEP Ohio coincident peak?
 - C. Or is it class non-coincident peak?

RESPONSE

- A. The Company used a 6 coincident peak in the base distribution case.
- B. Yes.
- C. No.

Prepared by: Andrea E. Moore

E.5 Energy, Demand and Emissions Savings

Table 4 presents the projected incremental annual GWh energy savings for each year as well as cumulative annual through 2019, TRC test results, net present value benefits, lifetime energy saved in thousand MWh, and lifetime cost of saved energy in 2017 dollars per kWh over the three-year period from 2017 to 2019.

Table 4. Incremental Annual Energy (GWh) Savings at Meter – 2017 to 2019

Consumer Sector	2017	2018	2019	2019 Cumulative Annual	Percent of Plan Total	Total Resource Cost Test (TRC)	TRC NPV Benefits (million 2017\$)	Lifetime Energy Saved (thousand MWh)	Lifetime Utility Cost of Saved Energy (2017\$/kWh)
Appliance Recycling	11.8	11.9	11.9	35.7	2.2%	1.3	\$9.9	285	\$0.033
Community Assistance	8.4	8.5	8.5	25.4	1.6%	0.8	(\$5.1)	385	\$0.061
e3smart	6.8	6.8	6.9	20.5	1.3%	4.0	\$10.5	262	\$0.013
Efficient Products	64.5	61.1	57.0	182.6	11.3%	4.1	\$96.8	2,615	\$0.009
Behavior Change	75.0	75.0	75.0	75.0	4.6%	1.7	\$2.9	225	\$0.019
In-Home Energy	8.7	8.3	8.6	25.7	1.6%	1.5	\$8.6	458	\$0.032
New Home	4.7	4.8	6.1	15.6	1.0%	1.0	(\$0.5)	326	\$0.022
Manufactured Home	2.2	2.5	2.5	7.2	0.4%	1.2	\$0.7	145	\$0.015
Intelligent Home & Demand Response	12.0	24.1	36.1	36.1	2.2%	1.2	\$1.8	72	\$0.148
Consumer Sector Total	194.3	202.9	212.6	423.7	26.1%	2.0	\$118.7	4,772	\$0.023
% Savings of Consumer Sector Sales	1.4%	1.4%	1.5%	3.0%					

Note: Behavior Change and Intelligent Home & Demand Response savings are not cumulative.

Business Sector	2017	2018	2019	2019 Cumulative Annual	Percent of Plan Total	Total Resource Cost Test (TRC)	TRC NPV Benefits (million 2017\$)	Lifetime Energy Saved (thousand MWh)	Lifetime Utility CSE (2017\$ / kWh)
Business Behavior Change	8.9	8.9	9.4	9.4	0.6%	1.3	\$0.3	27	\$0.031
Continuous Energy Improvement	19.8	23.2	23.1	66.0	4.1%	2.2	\$9.3	330	\$0.022
Data Center	16.6	17.1	14.3	48.0	3.0%	1.3	\$3.5	240	\$0.029
Efficient Products for Business	109.7	105.3	99.1	314.1	19.4%	1.9	\$130.8	3,445	\$0.011
New Construction and Major Renovation	27.6	28.2	28.8	84.6	5.2%	1.4	\$17.0	994	\$0.020
Express	14.4	14.8	14.7	43.9	2.7%	1.3	\$9.8	397	\$0.029
Microbusiness	9.9	9.7	10.1	29.7	1.8%	1.7	\$9.2	330	\$0.012
Process Efficiency	42.0	41.9	38.1	122.0	7.5%	2.4	\$60.8	1,855	\$0.008
Retro-Commissioning	8.6	9.4	10.2	28.2	1.7%	1.0	\$0.2	141	\$0.031
Self-Direct	13.2	13.3	13.4	39.9	2.5%	4.6	\$18.7	390	\$0.011
CHP	106.0	106.0	106.0	318.0	19.6%	1.2	\$43.5	6,042	\$0.0014
Business Sector Total	376.8	377.9	366.9	1,103.7	68.0%	1.6	\$297.4	14,191	\$0.010
% Savings of Sector Sales (includes Business & Cross Sectors)	1.3%	1.3%	1.3%	3.9%					
Note: Behavior Change savings are not cumulative.									
Cross Sector	2017	2018	2019	2019 Cumulative Annual	Percent of Plan Total	Total Resource Cost Test (TRC)	TRC NPV Benefits (million 2017\$)	Lifetime Energy Saved (thousand MWh)	Lifetime Utility CSE (2017\$ / kWh)
Multifamily	5.8	6.0	6.2	18.0	1.1%	1.6	\$5.4	274	\$0.025
Agriculture	1.7	1.7	1.8	5.1	0.3%	2.0	\$1.7	52	\$0.015
T&D Loss Reductions	20.0	20.0	20.0	60.0	3.7%	NA	NA	NA	NA
Customer EE Assessment Survey	4.0	4.0	4.0	12.0	0.7%	1.7	NA	NA	NA
Cross Sector Total	31.4	31.7	31.9	95.1	5.9%	0.5	(\$22.3)	326	\$0.11
Plan Total	602.5	612.5	611.5	1,622.5	100%	1.6	\$393.9	19,289	\$0.014
% Total Sales	1.33%	1.36%	1.35%	3.6%					

Note: The 2019 Cumulative Annual savings does not equal the sum of the 2017 to 2019 incremental annual values because of a variety of factors. Section totals may not sum to Plan totals due to rounding.

E.6 EE/PDRs Investment and Potential Job Creation

The estimated investment for these programs is approximately \$97.5 million in each year from 2017-2019, for a total \$292.5 million (inflation adjusted 2017\$, not present value), as shown in Table 7.

Table 7. Estimated Annual Total Investments by Program (millions)

Consumer Sector	2017	2018	2019	2017-2019 Total (cumulative)	Percent of Plan Total
Appliance Recycling	\$3.2	\$3.4	\$3.5	\$10.1	3.5%
Community Assistance	\$8.5	\$8.5	\$8.5	\$25.5	8.7%
e3smart	\$1.2	\$1.2	\$1.2	\$3.7	1.3%
Efficient Products	\$9.1	\$8.7	\$8.0	\$25.8	8.8%
Behavior Change	\$1.5	\$1.5	\$1.5	\$4.5	1.5%
In-Home Energy	\$5.3	\$5.1	\$5.2	\$15.6	5.3%
New Home	\$2.4	\$2.4	\$3.1	\$7.9	2.7%
Manufactured Home	\$0.7	\$0.8	\$0.8	\$2.3	0.8%
Intelligent Home & DR (expense)	\$3.0	\$4.2	\$5.5	\$12.7	4.3%
Intelligent Home & DR (capital)	\$2.3	\$2.3	\$2.3	\$6.8	2.3%
Consumer Sector Total	\$37.2	\$38.0	\$39.6	\$114.9	39.3%
Business Sector	2017	2018	2019	17-19 Total (cumulative)	Percent of Plan Total
Business Behavior Change	\$0.3	\$0.3	\$0.3	\$0.9	0.3%
Continuous Energy Improvement	\$2.3	\$2.8	\$2.7	\$7.8	2.7%
Data Center	\$2.6	\$2.7	\$2.2	\$7.5	2.6%
Efficient Products for Business	\$14.3	\$13.7	\$13.3	\$41.3	14.1%
New Construction/Major Renovation	\$6.8	\$7.1	\$7.2	\$21.1	7.2%
Express	\$4.1	\$4.2	\$4.2	\$12.6	4.3%
Microbusiness	\$1.4	\$1.4	\$1.4	\$4.3	1.5%
Process Efficiency	\$5.7	\$5.6	\$4.9	\$16.2	5.5%
Retro-Commissioning	\$1.5	\$1.6	\$1.7	\$4.8	1.6%
Self-Direct	\$1.5	\$1.5	\$1.5	\$4.5	1.6%
CHP	\$3.4	\$3.4	\$3.4	\$10.2	3.5%
Energy Efficiency Auction	\$0.2	\$0.2	\$0.2	\$0.6	0.2%
T&D Customer Efficiency Projects	\$0.2	\$0.2	\$0.2	\$0.6	0.2%
Business Outreach	\$1.6	\$1.6	\$1.7	\$4.9	1.7%
Business Sector Total	\$46.1	\$46.2	\$45.2	\$137.5	47.0%

Cross Sector	2017	2018	2019	2017-2019 Total (cumulative)	Percent of Plan Total
Multifamily	\$2.4	\$2.5	\$2.5	\$7.4	2.5%
Agriculture	\$0.3	\$0.3	\$0.3	\$0.9	0.3%
Customer EE Assessment Survey	\$0.2	\$0.2	\$0.2	\$0.6	0.2%
Efficient Financing	\$1.0	\$1.0	\$1.0	\$3.0	1.0%
Community Energy Savers	\$0.5	\$0.5	\$0.5	\$1.5	0.5%
Education and Training	\$0.4	\$0.4	\$0.4	\$1.2	0.4%
Targeted Advertising	\$6.0	\$6.0	\$6.0	\$18.0	6.2%
Research and Development	\$2.5	\$2.5	\$2.5	\$7.5	2.6%
Cross Sector Total	\$13.3	\$13.4	\$13.4	\$40.1	13.7%
Plan Total Investment	\$96.6	\$97.6	\$98.2	\$292.5	100.0%

(1) Savings are not projected for Research and Development, T&D Customer Efficiency, Energy Efficiency Auction, gridSMART EE/PDR, and Community Energy Savers. AEP Ohio also will conduct program evaluation and other essential program support functions, such as compliance and reporting, database management, contracting and payables, and Plan cost-benefit analysis.

(2) Cross-Sector Costs include support and other services, including general education and training, and targeted advertising, efficient financing, and most of the activities listed in (1) above.

(3) Section or annual totals may not sum to Plan totals due to rounding.

To firm up cost estimates and make any necessary budget and schedule changes, AEP Ohio may re-negotiate existing contracts for ongoing programs or issue Requests for Proposals (RFPs) for implementation contractors to bid on the work, and require them to submit detailed budgets along with estimated savings and implementation schedules. All new programs may be competitively bid through an RFP process. The cost for incremental internal management and third party evaluation, measurement and verification activities, and future plan development is included in the cost of the Plan. It is anticipated that these costs will not exceed ten percent of the total costs for the Plan.

Potential Job Creation

To capture the full economic impacts of the investments in energy efficiency, three separate effects (direct, indirect, and induced) must be examined for each change in expenditure. The sum of these three effects yields the total effect resulting from a single expenditure.

- The **direct effect** refers to the on-site or immediate effects produced by expenditures. In the case of installing energy efficiency upgrades in a home or business, the direct effect is the on-site expenditures and jobs of the construction or trade contractors hired to carry out the work.
- The **indirect effect** refers to the increase in economic activity that occurs when a contractor or vendor receives payment for goods or services delivered and is

Total Resource Cost (TRC) Test: Measures are cost effective from this perspective if their avoided costs are greater than the sum of the measure costs and the EE/PDR program administrative costs.

AEP Ohio used the TRC test to guide which EE/PDR programs to include in the Plan, noting that the Plan as a whole passes the TRC test as required by the PUCO. Most measures passed the TRC test. The Plan and the EE/PDR programs in the Plan are cost effective by industry standards.

Table 9 presents the overall benefit cost ratios for the consumer sector, the business sector, and the cross sector, and the overall Plan including all costs from other activities.

Table 9. Cost-effectiveness Ratios – 2017 to 2019

Consumer Sector	Total Resource Cost Test (TRC)	Utility Cost Test (UCT)	Participant Cost Test (PCT)	Rate Impact Measure Test (RIM)
Appliance Recycling	1.3	1.3	N/A	0.3
Community Assistance	0.8	0.8	N/A	0.3
e3smart	4.0	4.0	22.8	0.4
Efficient Products	4.1	5.5	15.1	0.4
Behavior Change	1.7	1.7	N/A	0.2
In-Home Energy	1.5	1.8	5.9	0.5
New Home	1.0	1.7	2.9	0.4
Manufactured Home	1.2	2.0	4.2	0.3
Intelligent Home & Demand Response	1.2	1.1	2.3	0.6
Consumer Sector Total	2.1	2.2	9.3	0.4

Business Sector	Total Resource Cost Test (TRC)	Utility Cost Test (UCT)	Participant Cost Test (PCT)	Rate Impact Measure Test (RIM)
Business Behavior Change	1.3	1.7	6.5	0.4
Continuous Energy Improvement	2.2	2.4	30.4	0.3
Data Center	1.3	2.4	4.1	0.4
Efficient Products for Business	1.9	7.4	3.0	0.7
New Construction and Major Renovation	1.4	2.9	2.9	0.5
Express	1.3	3.2	2.9	0.6
Microbusiness	1.7	5.6	2.8	0.7
Process Efficiency	2.4	6.9	3.9	0.7
Retro-Commissioning	1.0	1.7	4.5	0.3
Self-Direct	4.6	7.0	11.7	0.5
CHP	1.2	28.7	0.9	1.3
Business Sector Total (includes Other Costs)	1.6	6.4	2.4	0.7
Cross Sector	Total Resource Cost Test (TRC)	Utility Cost Test (UCT)	Participant Cost Test (PCT)	Rate Impact Measure Test (RIM)
Multifamily	1.6	2.1	4.5	0.5
Agriculture	2.0	4.4	4.0	0.6
Customer EE Assessment Survey	1.7	1.7	1.7	0.3
Cross Sector Total (includes Other Costs)	0.4	0.5	4.4	0.3
Plan Total (includes Other Costs)	(TRC)	(UCT)	(PCT)	(RIM)
	1.6	4.0	2.8	0.7

Projected Net Benefits

The formulas used to determine the net benefits for each benefit-cost test are provided in Table 10. All tests are evaluated by calculating the net present values over the lifetimes of the measures covered by the 20-year planning horizon. The total net benefits for each benefit-cost test for the 2017-2019 EE/PDR Plan are calculated by subtracting the value(s) in the denominator of each formula from the value(s) in the numerator. For example, subtracting both Administrative Costs (B) and Incentive Costs (C) from the Avoided Costs (A) results in the the UCT net benefits. Table 11 presents the present value costs for the 2017-2019 EE/PDR Plan in present value 2017 dollars (8.29% discount rate). The Avoided Costs (A) and Bill Reductions (E) result from energy

C.3 Residential Measure Characteristics by Program

Table 43. Residential Measure Characteristics (at meter savings)

Efficiency Measure	Base Measure	Program	Decision Type	Units	Energy Impact (kWh/unit)	Coincident Summer Peak Impact (W/unit)	Measure Life	Base Incentive (\$/unit)	Incremental Cost (\$/unit)	Admin Cost (\$/unit)
A/C Cycling	0 hours of control	Air Conditioning Control - Res	CTR	Per Home	481	2.08	1	\$30.00	\$100.00	\$47.08
Refrigerator Retirement	Secondary Refrigerator	Appliance Recycling	REM	Refrigerator	727	0.15	8	\$140.00	\$0.00	\$29.78
Freezer Retirement	Secondary Freezer	Appliance Recycling	REM	Freezer	640	0.16	8	\$140.00	\$0.00	\$26.23
Air Source Heat Pump SEER 14.5, COP 2.49	Electric Resistance Forced Air Furnace	Community Assistance	RET	Ton	2,707	0.02	18	\$1,006.25	\$1,006.25	\$1,524.92
ENERGY STAR® Window / Room AC (DUB)	EER 8.5 Window AC	Community Assistance	DUB	Unit	68	1.38	12	\$29.90	\$29.90	\$38.29
Reduced ACHnat 0.3 - Heat Pump	ACH 0.6	Community Assistance	RET	Home	1,712	0.01	15	\$530.00	\$530.00	\$964.61
Reduced ACHnat 0.3 - Central A/C - Non-EL Heat	ACH 0.6	Community Assistance	RET	Home	17	0.90	15	\$530.00	\$530.00	\$9.59
Reduced ACHnat 0.3 - Central A/C - EL Heat	ACH 0.6	Community Assistance	RET	Home	3,407	0.00	15	\$530.00	\$530.00	\$1,919.62
Ceiling Ins. R-30 - Heat Pump	R-25 Ceiling	Community Assistance	RET	1000 sqft footprint	98	0.02	20	\$700.00	\$700.00	\$55.39
Ceiling Ins. R-30 - Central A/C - Non-EL Heat	R-25 Ceiling	Community Assistance	RET	1000 sqft footprint	2	0.90	20	\$700.00	\$700.00	\$1.23
Ceiling Ins. R-30 - Central A/C - EL Heat	R-25 Ceiling	Community Assistance	RET	1000 sqft footprint	194	0.01	20	\$700.00	\$700.00	\$109.55
Ceiling Insul R-45 - Heat Pump	R-25 Ceiling	Community Assistance	RET	1000 sqft footprint	262	0.02	20	\$890.00	\$890.00	\$147.71
Ceiling Insul R-45 - Central A/C - Non-EL Heat	R-25 Ceiling	Community Assistance	RET	1000 sqft footprint	6	0.90	20	\$890.00	\$890.00	\$3.28
Ceiling Insul R-45 - Central A/C - EL Heat	R-25 Ceiling	Community Assistance	RET	1000 sqft footprint	519	0.01	20	\$890.00	\$890.00	\$292.14
Wall Insul. R-11 - Heat Pump	Un-Insulated Wall	Community Assistance	RET	1000 sqft wall area	2,028	0.05	25	\$1,300.00	\$1,300.00	\$1,142.43
Wall Insul. R-11 - Central A/C - Non-EL Heat	Un-Insulated Wall	Community Assistance	RET	1000 sqft wall area	45	2.33	25	\$1,300.00	\$1,300.00	\$25.37
Wall Insul. R-11 - Central A/C - EL Heat	Un-Insulated Wall	Community Assistance	RET	1000 sqft wall area	4,011	0.01	25	\$1,300.00	\$1,300.00	\$2,259.49
Underbelly Insulation R-19 - Heat Pump	Un-Insulated Floor	Community Assistance	RET	100 sqft floor area	221	0.02	25	\$122.00	\$122.00	\$124.63
Underbelly Insulation R-19 - Central A/C - EL Heat	Un-Insulated Floor	Community Assistance	RET	100 sqft floor area	438	0.01	25	\$122.00	\$122.00	\$246.49
1W LED Night Light	7W Incandescent Light	Community Assistance	ROB	Lamp	20	0.00	8	\$2.00	\$2.00	\$11.27
LED Lighting 8W - Indoor	60W Incandescent	Community Assistance	ROB	Lamp	38	0.08	15	\$5.41	\$5.41	\$21.61



A unit of American Electric Power

Efficiency Measure	Base Measure	Program	Decision Type	Units	Energy Impact (kWh/unit)	Coincident Summer Peak Impact (W/unit)	Measure Life	Base Incentive (\$/unit)	Incremental Cost (\$/unit)	Admin Cost (\$/unit)
LED Lighting 8W - Outdoor	60W Incandescent	Community Assistance	ROB	Lamp	41	0.00	15	\$5.41	\$5.41	\$23.03
LED Lighting 15W - Indoor	Mix of 75W and 100W incandescent	Community Assistance	ROB	Lamp	62	0.08	15	\$8.59	\$8.59	\$35.16
LED Lighting 15W - Outdoor	Mix of 75W and 100W incandescent	Community Assistance	ROB	Lamp	67	0.00	15	\$8.59	\$8.59	\$37.51
High Eff. Elec. Water Heat - Tank - .95 EF (DUB)	Average Existing Electric Water Heater - 0.90 EF	Community Assistance	DUB	Unit	176	0.09	20	\$287.15	\$287.15	\$99.43
Heat Pump Water Heater - 2.0 EF	Standard Electric Water Heater - .945 EF	Community Assistance	ROB	Unit	1,685	0.09	10	\$888.50	\$888.50	\$949.07
Heat Pump Water Heater - 2.0 EF (DUB)	Average Existing Electric Water Heater - 0.90 EF	Community Assistance	DUB	Unit	1,844	0.09	10	\$492.39	\$492.39	\$1,039.03
Instantaneous Electric Water Heater - .99 EF	Standard Electric Water Heater - .945 EF	Community Assistance	ROB	Unit	145	0.09	13	\$666.80	\$666.80	\$81.78
Instantaneous Electric Water Heater - .99 EF (DUB)	Average Existing Electric Water Heater - 0.90 EF	Community Assistance	DUB	Unit	305	0.09	13	\$476.11	\$476.11	\$171.74
DHW Pipe Insulation R-4 10 feet	10 feet of uninsulated (R-1) Hot Water Pipe	Community Assistance	RET	10 Linear Feet	266	0.11	15	\$55.00	\$55.00	\$149.86
Low Flow Faucet Aerator, 1.5 GPM - EDHW	Average Existing Stock Aerator (2.2 GPM)	Community Assistance	RET	Faucet	25	0.12	12	\$2.80	\$2.80	\$13.80
Low Flow (1.25 GPM) showerhead	2.87 GPM Showerhead	Community Assistance	RET	Shower	237	0.11	9	\$11.00	\$11.00	\$133.52
Efficient Refrigerator (ENERGY STAR® or Better) (DUB)	Average Existing Refrigerator	Community Assistance	DUB	Refrigerator	231	0.15	17	\$832.88	\$832.88	\$129.92
Refrigerator Retirement	Secondary Refrigerator	Community Assistance	REM	Refrigerator	727	0.15	8	\$140.00	\$0.00	\$409.50
ECM Fan Motor - Heat Pump	Std PSC HVAC Motor	Community Assistance	RET	Home	675	0.20	18	\$90.68	\$90.68	\$380.27
ECM Fan Motor - Central A/C - Non-EL Heat	Std PSC HVAC Motor	Community Assistance	RET	Home	675	0.20	18	\$90.68	\$90.68	\$380.27
ECM Fan Motor - Central A/C - EL Heat	Std PSC HVAC Motor	Community Assistance	RET	Home	675	0.20	18	\$90.68	\$90.68	\$380.27
Shower Start/Stop	No Start/Stop on Shower	Community Assistance	RET	Unit	245	0.11	5	\$24.95	\$24.95	\$138.11
Weatherstripping and Door Sweep	No Weatherstripping	e3smart	RET	Home	82	0.12	11	\$1.00	\$1.00	\$8.35
1W LED Night Light	7W Incandescent Light	e3smart	RET	Lamp	20	0.00	8	\$2.00	\$2.00	\$2.05
LED Lighting 8W - Indoor for Kit	60W Incandescent	e3smart	RET	Lamp	41	0.08	15	\$5.41	\$5.41	\$4.20



Efficiency Measure	Base Measure	Program	Decision Type	Units	Energy Impact (kWh/unit)	Coincident Summer Peak Impact (W/unit)	Measure Life	Base Incentive (\$/unit)	Incremental Cost (\$/unit)	Admin Cost (\$/unit)
LED Lighting 8W - Outdoor for Kit	60W Incandescent	e3smart	RET	Lamp	41	0.00	15	\$5.41	\$5.41	\$4.19
LED Lighting 15W - Indoor for Kit	Mix of 75W and 100W incandescent	e3smart	RET	Lamp	62	0.08	15	\$8.59	\$8.59	\$6.39
LED Lighting 15W - Outdoor for Kit	Mix of 75W and 100W incandescent	e3smart	RET	Lamp	67	0.00	15	\$8.59	\$8.59	\$6.82
Low Flow (1.25 GPM) showerhead	2.87 GPM Showerhead	e3smart	RET	Shower	237	0.11	9	\$2.75	\$2.75	\$24.28
Hot Water Temp Gauge (Tank Temperature Turn Down)	No Temp Gauge	e3smart	RET	Unit	151	0.09	4	\$1.00	\$1.00	\$15.50
Low Flow Faucet Aerator, 1.5 GPM - EDHW -Kitchen	Average Existing Stock Aerator (2.2 GPM)	e3smart	RET	Faucet	25	0.12	12	\$0.50	\$0.50	\$2.51
Low Flow Faucet Aerator, 1.5 GPM - EDHW - Bathroom	Average Existing Stock Aerator (2.2 GPM)	e3smart	RET	Faucet	42	0.12	12	\$0.50	\$0.50	\$4.30
LED Lighting 8W - Indoor	60W Incandescent	Efficient Products	ROB	Lamp	38	0.08	15	\$3.25	\$5.41	\$1.96
LED Lighting 8W - Outdoor	60W Incandescent	Efficient Products	ROB	Lamp	41	0.00	15	\$3.25	\$5.41	\$2.09
LED Lighting 15W - Indoor	Mix of 75W and 100W incandescent	Efficient Products	ROB	Lamp	62	0.08	15	\$5.00	\$8.59	\$3.20
LED Lighting 15W - Outdoor	Mix of 75W and 100W incandescent	Efficient Products	ROB	Lamp	67	0.00	15	\$5.00	\$8.59	\$3.41
LED Lighting 8W - Indoor (CFL Base)	13W CFL	Efficient Products	ROB	Lamp	3	0.09	15	\$3.25	\$3.78	\$0.16
LED Lighting 8W - Outdoor (CFL Base)	13W CFL	Efficient Products	ROB	Lamp	4	0.00	15	\$3.25	\$3.78	\$0.22
LED Lighting 12W - Indoor (CFL Base)	23W CFL	Efficient Products	ROB	Lamp	6	0.09	15	\$3.75	\$3.78	\$0.31
LED Lighting 12W - Outdoor (CFL Base)	23W CFL	Efficient Products	ROB	Lamp	9	0.00	15	\$3.75	\$3.78	\$0.45
5W Chandelier LED bulb	20-25W Incandescent Chandelier/Specialty Bulb	Efficient Products	ROB	Lamp	20	0.09	15	\$3.75	\$7.50	\$1.01
Hardwired Dimmer Switch	Two 60W Bulbs without Dimmer Switch	Efficient Products	RET	Dimmer	24	0.21	10	\$8.00	\$30.00	\$1.23
Indoor Wall-mounted Motion Sensor	Two 60W Bulbs without a Motion Sensor	Efficient Products	RET	Sensor	39	0.13	8	\$20.00	\$42.00	\$2.01
Indoor Fixture-mounted Motion Sensor	Two 60W Bulbs without a Motion Sensor	Efficient Products	RET	Sensor	29	0.18	8	\$20.00	\$66.00	\$1.47
Outdoor Motion Sensor	No Motion Sensor	Efficient Products	RET	Sensor	56	0.00	8	\$20.00	\$33.00	\$2.86



Efficiency Measure	Base Measure	Program	Decision Type	Units	Energy Impact (kWh/unit)	Coincident Summer Peak Impact (W/unit)	Measure Life	Base Incentive (\$/unit)	Incremental Cost (\$/unit)	Admin Cost (\$/unit)
Solar Water Heat (DUB)	Average Existing Electric Water Heater - 0.90 EF	Efficient Products	DUB	Unit	2,442	0.16	20	\$2,250.00	\$4,479.21	\$125.05
DHW Pipe Insulation R-4 10 feet	10 feet of uninsulated (R-1) Hot Water Pipe	Efficient Products	RET	10 Linear Feet	266	0.11	15	\$30.00	\$55.00	\$13.62
Low Flow Faucet Aerator, 1.5 GPM - EDHW	Average Existing Stock Aerator (2.2 GPM)	Efficient Products	RET	Faucet	25	0.12	12	\$2.80	\$2.80	\$1.25
Low Flow (1.25 GPM) showerhead	2.87 GPM Showerhead	Efficient Products	RET	Shower	192	0.11	9	\$6.00	\$6.00	\$9.83
VSD Pool Pump	Code Efficiency One Speed Pump	Efficient Products	ROB	Pump	1,170	1.46	10	\$200.00	\$750.00	\$59.92
Premium Efficiency Pool Pumps	Code Efficiency One Speed Pump	Efficient Products	ROB	Pump	409	1.40	10	\$25.00	\$50.00	\$20.95
Heavy Duty Outdoor Timer for Pool Pump	Pool Pump Run Continuously Without Timer	Efficient Products	RET	Pump	131	2.33	10	\$25.00	\$200.00	\$6.69
Efficient Refrigerator (ENERGY STAR® or Better)	Code-Compliant Refrigerator	Efficient Products	ROB	Refrigerator	104	0.18	17	\$50.00	\$89.75	\$5.30
Efficient Refrigerator (ENERGY STAR® or Better) (DUB)	Average Existing Refrigerator	Efficient Products	DUB	Refrigerator	231	0.15	17	\$37.53	\$37.53	\$11.81
ENERGY STAR® Freezer	Code Freezer	Efficient Products	ROB	Freezer	36	0.16	11	\$10.00	\$35.00	\$1.85
ENERGY STAR® Freezer (DUB)	Average Existing Freezer	Efficient Products	DUB	Freezer	256	0.16	11	\$10.00	\$72.17	\$13.13
ENERGY STAR® Dehumidifier	Non-ENERGY STAR® Dehumidifier	Efficient Products	ROB	Dehumidifier	207	0.23	12	\$25.00	\$60.00	\$10.58
5-plug Smart Strip Power Bar	No Sensor Power Strip	Efficient Products	RET	Power Strip	57	0.11	4	\$10.00	\$16.00	\$2.89
7-plug Smart Strip Power Bar	No Sensor Power Strip	Efficient Products	RET	Power Strip	103	0.12	4	\$10.00	\$26.00	\$5.26
ENERGY STAR® v. 5.3 Television	Code Compliant TV	Efficient Products	ROB	TV	272	0.15	6	\$1.00	\$1.00	\$13.90
ENERGY STAR® Most Efficient Television	Code Compliant TV	Efficient Products	ROB	TV	314	0.15	6	\$1.00	\$1.00	\$16.09
ENERGY STAR® Set Top Boxes	Non-ENERGY STAR® Set Top Boxes	Efficient Products	ROB	Box	62	0.07	5	\$19.01	\$19.01	\$3.16
ENERGY STAR® Monitor	Code Compliant Monitor	Efficient Products	ROB	Monitor	14	0.13	5	\$11.00	\$11.00	\$0.72
ENERGY STAR® Dishwasher - Elec DHW	Code Compliant Dishwasher (2013 Code)	Efficient Products	ROB	Dishwasher	37	0.10	11	\$25.00	\$50.00	\$1.89
ENERGY STAR® Dishwasher - Elec DHW (DUB)	Average Existing Dishwasher (2010 Code)	Efficient Products	DUB	Dishwasher	85	0.10	11	\$14.78	\$14.78	\$4.35



Efficiency Measure	Base Measure	Program	Decision Type	Units	Energy Impact (kWh/unit)	Coincident Summer Peak Impact (W/unit)	Measure Life	Base Incentive (\$/unit)	Incremental Cost (\$/unit)	Admin Cost (\$/unit)
ENERGY STAR® Dishwasher - Non-ELDHW	Code Compliant Dishwasher (2013 Code)	Efficient Products	ROB	Dishwasher	16	0.10	11	\$25.00	\$50.00	\$0.83
ENERGY STAR® Dishwasher - Non-ELDHW (DUB)	Average Existing Dishwasher (2010 Code)	Efficient Products	DUB	Dishwasher	64	0.10	11	\$14.78	\$14.78	\$3.29
Convection Oven	Conventional Oven	Efficient Products	ROB	Oven	67	0.54	12	\$50.00	\$50.00	\$3.45
Clothes Washer - Tier 3 >= 2.2 MEF-w/gas or no dry	Fed Standard 1.72 MEF	Efficient Products	ROB	Unit	130	0.14	11	\$50.00	\$101.43	\$6.64
Clothes Washer - Tier 3 >= 2.2 MEF-w/gas or no dry (DUB)	Average Existing Clothes Washer (1.04 MEF)	Efficient Products	DUB	Unit	173	0.14	11	\$29.98	\$29.98	\$8.86
Clothes Washer - Tier 3 >= 2.2 MEF-w/elec dry	Fed Standard 1.72 MEF	Efficient Products	ROB	Unit	393	0.14	11	\$50.00	\$101.43	\$20.12
Clothes Washer - Tier 3 >= 2.2 MEF-w/elec dry (DUB)	Average Existing Clothes Washer (1.04 MEF)	Efficient Products	DUB	Unit	524	0.11	11	\$29.98	\$29.98	\$26.84
Heat Pump Clothes Dryer (CEF >= 5.0) (Elec Dry)	Standard Vented Electric Dryer (CEF = 3.73)	Efficient Products	ROB	Unit	137	0.18	14	\$350.00	\$350.00	\$7.00
ENERGY STAR® Air Purifier/Cleaner	Non-ENERGY STAR® Air Purifier/Cleaner	Efficient Products	ROB	Purifier	569	0.11	9	\$50.00	\$70.00	\$29.15
High Performance Circulating Pump (DHW)	Conventional Circulator Pump on HW tank	Efficient Products	ROB	Pump	354	0.09	15	\$50.00	\$300.00	\$18.13
Home Energy Report	No Report	HER	BEH	Home	200	0.05	1	\$0.00	\$0.00	\$4.00
Tier 1 GSHP, Closed Loop, water to air	SEER 14, 11EER Air Source Heat Pump	In-Home Energy	ROB	Ton	518	0.07	18	\$500.00	\$1,203.00	\$199.12
Tier 1 GSHP, Closed Loop, water to air (DUB)	SEER 10, Air Source Heat Pump	In-Home Energy	DUB	Ton	829	0.19	18	\$500.00	\$525.00	\$318.25
Tier 2 GSHP, Closed Loop, water to air	SEER 14, 11EER Air Source Heat Pump	In-Home Energy	ROB	Ton	653	0.10	18	\$500.00	\$1,203.00	\$250.85
Tier 2 GSHP, Closed Loop, water to air (DUB)	SEER 10, Air Source Heat Pump	In-Home Energy	DUB	Ton	963	0.19	18	\$500.00	\$525.00	\$369.98
Tier 3 GSHP, Closed Loop, water to air	SEER 14, 11EER Air Source Heat Pump	In-Home Energy	ROB	Ton	712	0.11	18	\$500.00	\$1,203.00	\$273.55
Tier 3 GSHP, Closed Loop, water to air (DUB)	SEER 10, Air Source Heat Pump	In-Home Energy	DUB	Ton	1,022	0.19	18	\$500.00	\$525.00	\$392.68



Efficiency Measure	Base Measure	Program	Decision Type	Units	Energy Impact (kWh/unit)	Coincident Summer Peak Impact (W/unit)	Measure Life	Base Incentive (\$/unit)	Incremental Cost (\$/unit)	Admin Cost (\$/unit)
Tier 1 GSHP, Open Loop, water to air	SEER 14, 11 EER Air Source Heat Pump	In-Home Energy	ROB	Ton	691	0.10	18	\$500.00	\$1,203.00	\$265.45
Tier 1 GSHP, Open Loop, water to air (DUB)	SEER 10, Air Source Heat Pump	In-Home Energy	DUB	Ton	1,001	0.19	18	\$500.00	\$525.00	\$384.57
Tier 2 GSHP, Open Loop, water to air	SEER 14, 11 EER Air Source Heat Pump	In-Home Energy	ROB	Ton	801	0.12	18	\$500.00	\$1,203.00	\$307.49
Tier 2 GSHP, Open Loop, water to air (DUB)	SEER 10, Air Source Heat Pump	In-Home Energy	DUB	Ton	1,111	0.19	18	\$500.00	\$525.00	\$426.62
Tier 3 GSHP, Open Loop, water to air	SEER 14, 11 EER Air Source Heat Pump	In-Home Energy	ROB	Ton	936	0.14	18	\$500.00	\$1,203.00	\$359.42
Tier 3 GSHP, Open Loop, water to air (DUB)	SEER 10, Air Source Heat Pump	In-Home Energy	DUB	Ton	1,246	0.20	18	\$500.00	\$525.00	\$478.54
Air Source Heat Pump SEER 15, COP 2.49	SEER 14, 11 EER Air Source Heat Pump	In-Home Energy	ROB	Ton	95	0.48	18	\$200.00	\$274.15	\$36.35
Air Source Heat Pump SEER 15, COP 2.49 (DUB)	SEER 10, Air Source Heat Pump	In-Home Energy	DUB	Ton	662	0.25	18	\$119.64	\$119.64	\$254.44
SEER 15 CAC - Non-EL Heat	SEER 13.0 CAC	In-Home Energy	ROB	Ton	68	0.90	18	\$50.00	\$184.25	\$26.10
SEER 15 CAC - Non-EL Heat (DUB)	SEER 10.0 CAC	In-Home Energy	DUB	Ton	221	0.90	18	\$50.00	\$80.41	\$84.81
SEER 15 CAC - EL Heat	SEER 13.0 CAC	In-Home Energy	ROB	Ton	68	0.90	18	\$100.00	\$184.25	\$26.10
SEER 15 CAC - EL Heat (DUB)	SEER 10.0 CAC	In-Home Energy	DUB	Ton	221	0.90	18	\$80.41	\$80.41	\$84.81
Ductless Mini Split HP SEER 15	Ductless Mini Split HP SEER 13	In-Home Energy	ROB	Ton	76	1.29	15	\$25.00	\$50.00	\$29.23
Ductless Mini Split HP SEER 18	Ductless Mini Split HP SEER 13	In-Home Energy	ROB	Ton	159	1.29	15	\$200.00	\$377.11	\$60.90
ENERGY STAR* Window / Room AC	CEER 10.9 Window AC	In-Home Energy	ROB	Unit	17	1.27	12	\$16.19	\$16.19	\$6.40
ENERGY STAR* Window / Room AC (DUB)	EER 8.5 Window AC	In-Home Energy	DUB	Unit	68	1.27	12	\$25.00	\$29.90	\$26.10
Ground Source Heat Pump (Elec Res Base)	Electric Baseboard Heating	In-Home Energy	RET	Ton	3,118	0.01	18	\$2,000.00	\$6,031.03	\$1,197.66
ENERGY STAR* Air Source Heat Pump (Elec Res Base)	Electric Baseboard Heating	In-Home Energy	RET	Ton	2,612	0.02	18	\$500.00	\$1,809.31	\$1,003.37
ECM Fan Motor - Heat Pump	Std PSC HVAC Motor	In-Home Energy	RET	Home	675	0.20	18	\$50.00	\$90.68	\$259.28
ECM Fan Motor - Central A/C - Non-EL Heat	Std PSC HVAC Motor	In-Home Energy	RET	Home	675	0.20	18	\$50.00	\$90.68	\$259.28
ECM Fan Motor - Central A/C - EL Heat	Std PSC HVAC Motor	In-Home Energy	RET	Home	675	0.20	18	\$50.00	\$90.68	\$259.28
Duct Sealing and Insulation - Heat Pump	Leaky Un-Insulated Ducts	In-Home Energy	RET	Home	1,511	0.02	20	\$70.00	\$760.00	\$580.48
Duct Sealing and Insulation - CAC - Non-EL Heat	Leaky Un-Insulated Ducts	In-Home Energy	RET	Home	35	0.98	20	\$70.00	\$760.00	\$13.46
Duct Sealing and Insulation - CAC - EL Heat	Leaky Un-Insulated Ducts	In-Home Energy	RET	Home	3,430	0.01	20	\$70.00	\$760.00	\$1,317.60



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Efficiency Measure	Base Measure	Program	Decision Type	Units	Energy Impact (kWh/unit)	Coincident Summer Peak Impact (W/unit)	Measure Life	Base Incentive (\$/unit)	Incremental Cost (\$/unit)	Admin Cost (\$/unit)
CAC Tune-Up	No Tune-Up	In-Home Energy	RET	Ton	30	0.40	5	\$25.00	\$192.50	\$11.57
NEST Consumer Controls - Heat Pump - (DUB)	Non-Programmable Thermostat	In-Home Energy	DUB	Home	804	0.00	15	\$70.00	\$98.61	\$308.79
NEST Consumer Controls - Non-EL Heat - (DUB)	Non-Programmable Thermostat	In-Home Energy	DUB	Home	50	0.00	15	\$35.00	\$98.61	\$19.39
Reduced ACHnat 0.3 - Heat Pump	ACH 0.6	In-Home Energy	RET	Home	1,712	0.01	15	\$200.00	\$530.00	\$657.69
Reduced ACHnat 0.3 - Central A/C - Non-EL Heat	ACH 0.6	In-Home Energy	RET	Home	17	0.90	15	\$50.00	\$530.00	\$6.54
Reduced ACHnat 0.3 - Central A/C - EL Heat	ACH 0.6	In-Home Energy	RET	Home	3,407	0.00	15	\$200.00	\$530.00	\$1,308.83
ENERGY STAR® 50 CFM Bathroom Ventilating Fan	Code-Compliant Ventilating Fan	In-Home Energy	ROB	Fan	88	0.11	19	\$20.00	\$43.50	\$33.80
Solar Attic Ventilating Fans	Passive Ventilation	In-Home Energy	RET	Fan	8	0.98	10	\$10.00	\$500.00	\$3.15
Ceiling Ins. R-30 - Heat Pump	R-25 Ceiling	In-Home Energy	RET	1000 sqft footprint	98	0.02	20	\$225.00	\$700.00	\$37.77
Ceiling Ins. R-30 - Central A/C - Non-EL Heat	R-25 Ceiling	In-Home Energy	RET	1000 sqft footprint	2	0.90	20	\$225.00	\$700.00	\$0.84
Ceiling Ins. R-30 - Central A/C - EL Heat	R-25 Ceiling	In-Home Energy	RET	1000 sqft footprint	194	0.01	20	\$225.00	\$700.00	\$74.69
Ceiling Insul R-45 - Heat Pump	R-25 Ceiling	In-Home Energy	RET	1000 sqft footprint	262	0.02	20	\$225.00	\$890.00	\$100.71
Ceiling Insul R-45 - Central A/C - Non-EL Heat	R-25 Ceiling	In-Home Energy	RET	1000 sqft footprint	6	0.90	20	\$90.00	\$890.00	\$2.24
Ceiling Insul R-45 - Central A/C - EL Heat	R-25 Ceiling	In-Home Energy	RET	1000 sqft footprint	519	0.01	20	\$225.00	\$890.00	\$199.18
Wall Insul. R-11 - Heat Pump	Un-Insulated Wall	In-Home Energy	RET	1000 sqft wall area	2,028	0.05	25	\$225.00	\$1,300.00	\$778.93
Wall Insul. R-11 - Central A/C - Non-EL Heat	Un-Insulated Wall	In-Home Energy	RET	1000 sqft wall area	45	2.33	25	\$225.00	\$1,300.00	\$17.30
Wall Insul. R-11 - Central A/C - EL Heat	Un-Insulated Wall	In-Home Energy	RET	1000 sqft wall area	4,011	0.01	25	\$225.00	\$1,300.00	\$1,540.56
ENERGY STAR® Double Pane Windows - Heat Pump (DUB)	Single Pane Windows	In-Home Energy	DUB	100 sqft window area	847	0.17	25	\$82.36	\$82.36	\$325.35
ENERGY STAR® Double Pane Windows - Central A/C - Non-EL Heat (DUB)	Single Pane Windows	In-Home Energy	DUB	100 sqft window area	294	0.50	25	\$82.36	\$82.36	\$112.93
ENERGY STAR® Double Pane Windows - Central A/C - EL Heat (DUB)	Single Pane Windows	In-Home Energy	DUB	100 sqft window area	999	0.15	25	\$82.36	\$82.36	\$383.60
Triple Pane Windows - Heat Pump (DUB)	Single Pane Windows	In-Home Energy	DUB	100 sqft window area	1,439	0.15	25	\$137.27	\$137.27	\$552.92
Triple Pane Windows - Central A/C - Non-EL Heat	Single Pane Windows	In-Home Energy	DUB	100 sqft window area	464	0.48	25	\$90.00	\$137.27	\$178.11



Efficiency Measure	Base Measure	Program	Decision Type	Units	Energy Impact (kWh/unit)	Coincident Summer Peak Impact (W/unit)	Measure Life	Base Incentive (\$/unit)	Incremental Cost (\$/unit)	Admin Cost (\$/unit)
(DUB)										
Triple Pane Windows - Central A/C - EL Heat (DUB)	Single Pane Windows	In-Home Energy	DUB	100 sqft window area	2,415	0.09	25	\$137.27	\$137.27	\$927.74
Window Film (west facing windows)	No Film	In-Home Energy	RET	100 sqft window area	178	0.53	10	\$200.00	\$267.00	\$68.52
ENERGY STAR® Door - Heat Pump	Average Existing Door (1.75" thick wood, R-3.2)	In-Home Energy	RET	Door	30	0.02	20	\$15.00	\$64.71	\$11.61
ENERGY STAR® Door - Non-EL Heat	Average Existing Door (1.75" thick wood, R-3.2)	In-Home Energy	RET	Door	1	0.98	20	\$15.00	\$64.71	\$0.26
ENERGY STAR® Door - EL Heat	Average Existing Door (1.75" thick wood, R-3.2)	In-Home Energy	RET	Door	60	0.01	20	\$15.00	\$64.71	\$22.97
1W LED Night Light	7W Incandescent Light	In-Home Energy	RET	Lamp	20	0.00	8	\$1.00	\$2.00	\$7.68
LED Holiday Lights (300 bulb string)	300 x 0.48 W Incandescent Lights	In-Home Energy	RET	300 bulb string	26	0.00	15	\$5.00	\$10.00	\$10.09
High Eff. Elec. Water Heater - Tank - .95 EF (DUB)	Average Existing Electric Water Heater - .090 EF	In-Home Energy	DUB	Unit	176	0.09	20	\$50.00	\$287.15	\$67.79
Heat Pump Water Heater - 2.0 EF	Standard Electric Water Heater - .945 EF	In-Home Energy	ROB	Unit	1,685	0.09	10	\$500.00	\$888.50	\$647.09
Heat Pump Water Heater - 2.0 EF (DUB)	Average Existing Electric Water Heater - .090 EF	In-Home Energy	DUB	Unit	1,844	0.09	10	\$242.39	\$242.39	\$708.43
Instantaneous Electric Water Heater - .99 EF	Standard Electric Water Heater - .945 EF	In-Home Energy	ROB	Unit	145	0.09	13	\$400.00	\$666.80	\$55.76
Instantaneous Electric Water Heater - .99 EF (DUB)	Average Existing Electric Water Heater - .090 EF	In-Home Energy	DUB	Unit	305	0.09	13	\$226.11	\$226.11	\$117.10
Drain Water Heat Recovery (42% efficient or higher)	No Heat Recovery	In-Home Energy	RET	Unit	391	0.00	25	\$250.00	\$760.00	\$150.05
Shower Start/Stop	No Start/Stop on Shower	In-Home Energy	RET	Unit	245	0.11	5	\$10.00	\$24.95	\$94.17
Waterbed Insulating Pad	No Pad	In-Home Energy	RET	Pad	490	0.01	6	\$17.50	\$35.00	\$188.22
Residential Solar PV	Average Ohio Home w/o Solar PV	In-Home Energy	RET	kW Output	1,202	0.58	25	\$1,000.00	\$10,000.00	\$461.59



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Efficiency Measure	Base Measure	Program	Decision Type	Units	Energy Impact (kWh/unit)	Coincident Summer Peak Impact (W/unit)	Measure Life	Base Incentive (\$/unit)	Incremental Cost (\$/unit)	Admin Cost (\$/unit)
ENERGY STAR® Manufactured Homes - EL Heat	Average Manufactured Home	Manufactured Home	NEW	Home	11,947	0.04	20	\$2,500.00	\$5,000.00	\$1,223.74
Reduced ACHnat 0.3 - Heat Pump	ACH 0.6	New Home	NEW	Home	1,712	0.01	15	\$200.00	\$530.00	\$526.15
Reduced ACHnat 0.3 - Central A/C - Non-EL Heat	ACH 0.6	New Home	NEW	Home	17	0.90	15	\$50.00	\$530.00	\$5.23
Reduced ACHnat 0.3 - Central A/C - EL Heat	ACH 0.6	New Home	NEW	Home	3,407	0.00	15	\$200.00	\$530.00	\$1,047.07
ENERGY STAR® 50 CFM Bathroom Ventilating Fan	Code-Compliant Ventilating Fan	New Home	NEW	Fan	88	0.11	19	\$20.00	\$43.50	\$27.04
ENERGY STAR® Double Pane Windows - Heat Pump	Double Pane Windows	New Home	NEW	100 sqft window area	363	0.17	25	\$50.00	\$150.00	\$111.55
ENERGY STAR® Double Pane Windows - Central A/C - Non-EL Heat	Double Pane Windows	New Home	NEW	100 sqft window area	126	0.50	25	\$50.00	\$150.00	\$98.72
ENERGY STAR® Double Pane Windows - Central A/C - EL Heat	Double Pane Windows	New Home	NEW	100 sqft window area	428	0.15	25	\$50.00	\$150.00	\$131.52
Triple Pane Windows - Heat Pump	Double Pane Windows	New Home	NEW	100 sqft window area	617	0.15	25	\$180.00	\$250.00	\$189.57
Triple Pane Windows - Central A/C - Non-EL Heat	Double Pane Windows	New Home	NEW	100 sqft window area	199	0.48	25	\$75.00	\$250.00	\$61.07
Triple Pane Windows - Central A/C - EL Heat	Double Pane Windows	New Home	NEW	100 sqft window area	1,035	0.09	25	\$90.00	\$250.00	\$318.08
Heat Pump Water Heater - 2.0 EF	Standard Electric Water Heater - .945 EF	New Home	NEW	Unit	1,685	0.09	10	\$125.00	\$888.50	\$517.67
Drain Water Heat Recovery (42% efficient or higher)	No Heat Recovery	New Home	NEW	Unit	391	0.00	25	\$250.00	\$660.00	\$120.04
ENERGY STAR® 3.0 Qualified Home - Heat Pump	Code Construction	New Home	NEW	Home	3,389	0.15	20	\$1,000.00	\$2,329.00	\$1,041.26
ENERGY STAR® 3.0 Qualified Home - Central A/C - Non-EL Heat	Code Construction	New Home	NEW	Home	1,259	0.39	20	\$1,000.00	\$2,329.00	\$387.03
ENERGY STAR® 2.0/2.5 Qualified Home - Heat Pump	Code Construction	New Home	NEW	Home	3,393	0.16	20	\$500.00	\$1,674.00	\$1,042.62
ENERGY STAR® 2.0/2.5 Qualified Home - Central A/C - Non-EL Heat	Code Construction	New Home	NEW	Home	1,135	0.47	20	\$500.00	\$1,674.00	\$348.80

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Summary: Testimony Direct Testimony of Paul Chernick on Behalf of Natural Resources Defense Council electronically filed by Mr. Robert Dove on behalf of Natural Resources Defense Council