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Subject: IURC GAO 2014-1 -- Comments from Indiana Investor-Owned Electric Utilities
Attachments: IURC GAO 2014-1 -- June 9, 2014 comments of 5 IOU electric utilities-c.pdf

Please accept the attached comments in response to the IURC's GAO 2014-1, submitted on behalf of Duke Energy Indiana, Inc., Indiana Michigan Power Company, Indianapolis Power & Light Company, Northern Indiana Public Service Company, and Vectren Energy Delivery of Indiana, Inc.

Thank you,
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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

**IN RE GENERAL ADMINISTRATIVE ORDER
OF THE INDIANA UTILITY REGULATORY
COMMISSION 2014-1**

COMMENTS OF INDIANA'S INVESTOR-OWNED ELECTRIC UTILITIES IN RESPONSE TO THE COMMISSION'S GENERAL ADMINISTRATIVE ORDER 2014-1

Duke Energy Indiana, Inc., Indiana Michigan Power Company, Indianapolis Power & Light Company, Northern Indiana Public Service Company, and Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. (collectively the "Utilities") respectfully submit the following comments in response to the issues outlined in the Commission's General Administrative Order 2014-1.

The Utilities appreciate the opportunity to provide input to the Commission about utility-sponsored energy efficiency in Indiana. Some of the Utilities have been administering and delivering energy efficiency programs to customers for over 20 years, and all of the Utilities have had comprehensive energy efficiency programs in place and available to customers for at least the past 4 years, including implementation of programs under the auspices of the Commission's 2009 Phase II DSM Order. This collective experience with the design, administration, implementation, delivery, evaluation, and measurement of utility-sponsored energy efficiency programs has provided the Utilities with valuable insights into the issues raised in GAO 2014-1.

The Utilities are committed to continuing to provide a comprehensive portfolio of cost-effective energy efficiency programs to their retail electric customers. In fact, the Utilities recently filed individual DSM plans with the Commission in order to continue offering energy efficiency programs in 2015. As outlined in these comments, the Utilities believe that rather than reinstituting prescribed energy savings goals that ignore changing conditions, utility-sponsored energy efficiency in Indiana can continue to be offered while being improved in several respects, such as cost-effectiveness, fit with the individual utility's integrated resource plan, and mitigation of rate impacts. The Utilities' recommendations include: using individual IRP results as a key part of the basis for energy efficiency decisions; recognizing changing building codes and appliance efficiency standards; considering rate impacts associated with energy efficiency programs; requiring all Indiana retail electric utilities (not just jurisdictional utilities) to offer comprehensive energy efficiency programs to customers; eliminating any mandates to utilize third party administrators to deliver utilities' programs; and focusing on demand response as well as energy efficiency. Equally important are regulatory policies that work to overcome natural disincentives to utility pursuit of energy efficiency, by allowing for timely recovery of utilities' energy efficiency costs, including lost revenues, and offering incentives for successful energy efficiency programs.

The Utilities are still reviewing U.S. EPA's proposed rules regarding Section 111(d) of the Clean Air Act and would respectfully suggest that any use of energy efficiency programs required by the State to facilitate compliance would presumably be included in the State's implementation plan, and given the political and legal issues regarding the draft rule, it is premature to consider what role, if any, the Commission would play in facilitating such compliance.

I. <u>Appropriate energy efficiency goals for Indiana</u>

Indiana should focus on reasonably achievable and sustainable cost-effective energy efficiency programs that fit with the individual utility's integrated resource plan and needs, as opposed to imposing statewide energy savings goals across-the-board.

There are 3 major policy strategies that states currently use to advance utility-sponsored energy efficiency: integrated resource planning; public benefit funds; and energy efficiency resource standards.[1] For years, Indiana utilized the integrated resource planning ("IRP") strategy; Indiana's utilities designed and implemented their

[1] *The History of Energy Efficiency,* Alliance Commission on National Energy Efficiency Policy (January 2013).

own energy efficiency programs, consistent with the value of energy efficiency vis à vis their unique resource needs. This IRP focus was driven by Indiana's Powerplant Construction Act,[2] which requires utilities to demonstrate consideration of conservation and load management programs, among other things, prior to obtaining a certificate of public convenience and necessity ("CPCN") for the purchase, lease or construction of an electric generating facility.[3]

In 2009, via its Phase II DSM Order,[4] the Commission concluded that this individual utility-by-utility design and implementation of programs created inconsistencies across the state, both in terms of program availability as well as energy efficiency program intensity. The Commission's remedy was twofold: first, the Commission imposed annual, increasing energy savings goals upon the jurisdictional utilities; and second, the Commission mandated a number of "core" programs that were required to be offered to all jurisdictional utility customers, via a third party administrator.

The Commission's 2009 Phase II DSM Order thus represented a shift from an IRP energy efficiency strategy (as contemplated by Indiana's Powerplant Construction Act) to an administratively-implemented energy efficiency resource standard ("EERS") strategy. While the Phase II DSM Order achieved the Commission's goal of increasing energy efficiency program intensity and the availability of offerings to jurisdictional utility customers, in hindsight, the Phase II Order also led to certain consequences, including: a weaker link between energy efficiency programs and the utility's IRP

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[2] Ind. Code Ch. 8-1-8.5.

[3] Ind. Code Ch. § 8-1-8.5-2. The Commission in interpreting the statute has noted that planning for new power is not a simple task and the Utility Powerplant Construction Act is designed to give a utility certainty in the form of a CPCN in exchange for the necessity of prior approval (*In re the Matter of Indianapolis Power & Light*; IURC Cause No. 39236; 1992 Ind. PUC LEXIS 297 (Sept. 2, 1992). The Commission has further determined that the statute is clear and unambiguous on its face (*In the Matter of Wabash Valley*, IURC Cause No. 42762; 2005 Ind. PUC LEXIS 207 (June 15, 2005)). The Commission has also recognized that it has an ongoing obligation to carefully and fully review IRPs to assist in administration of the Powerplant Construction Act (*Order Reopening the Comment Period*, IURC Cause No. 43061 (May 31, 2006).

[4] *In re Verified Joint Petition*, IURC Cause No. 43426 Phase II Order (June 30, 2009) ("Phase II Order").

process; escalating energy efficiency program costs; administrative inefficiencies; material rate impacts; lack of recognition of energy efficiency savings resulting from increased building code standards and appliance efficiency standards; and a regulatory emphasis on energy efficiency almost to the exclusion of demand response.

Notably, when the Phase II Order was issued in 2009, the State Utility Forecasting Group projected a capacity shortfall (about 4000 MWs by 2020).[5] Thereafter, the economy collapsed as did anticipated electric demand growth. Despite this significant change in resource needs, the mandated DSM goals, calling for an almost 12% reduction in customer use over the 10 year savings period based on escalated DSM program offerings and costs, were not reconsidered. This highlights the need to have a more flexible framework that is responsive to such circumstances.

Each utility has unique resource needs, customer bases, market potentials, and avoided costs. These unique attributes, all of which play a part in determining optimal resource decisions, are effectively ignored when arbitrary EERS goals are imposed across-the-board. In contrast, a "bottoms up" integrated resource planning approach, which considers the utility's individual resource needs, avoided costs, market potential, and customers is more likely to produce optimal resource solutions for the utility and its customers.

The Utilities submit that a renewed emphasis on an IRP directed strategy for energy efficiency programs, as opposed to statewide, mandated EERS goals, will best serve customers and the State over the long term. An IRP focus will do more to ensure that only cost-effective and necessary programs are implemented, that energy efficiency savings from increased appliance efficiency standards and building codes will be recognized, that energy efficiency and demand response will both be evaluated and emphasized as potential resources, and that rate impacts will be moderated. At the same time, the Utilities are not recommending a slavish adherence to IRP results. We believe that in order to achieve sustainable energy efficiency programs, some flexibility and management judgment must be allowed. For example, a utility without near term

[5] http://www.purdue.edu/discoverypark/energy/assets/pdfs/SUFG/publications/2009_SUFG_Forecast.pdf

resource needs may nevertheless want to continue offering energy efficiency programs, in order to retain customer interest and the benefit of such program offerings when future needs arise.

The Utilities' view is consistent with practices in other states. For example, Kentucky law provides that:

> The commission may determine the reasonableness of demand-side management plans proposed by any utility under its jurisdiction. Factors to be considered in this determination include, but are not limited to, the following: (a) The specific changes in customers' consumption patterns which a utility is attempting to influence; (b) The cost and benefit analysis and other justification for specific demand-side management programs and measures included in a utility's proposed plan; (c) A utility's proposal to recover in rates the full costs of demand-side management programs, any net revenues lost due to reduced sales resulting from demand-side management programs, and incentives designed to provide positive financial rewards to a utility to encourage implementation of cost-effective demand-side management programs; (d) ***Whether a utility's proposed demand-side management programs are consistent with its most recent long-range integrated resource plan***; (e) Whether the plan results in any unreasonable prejudice or disadvantage to any class of customers; (f) The extent to which customer representatives and the Office of the Attorney General have been involved in developing the plan, including program design, cost recovery mechanisms, and financial incentives, and if involved, the amount of support for the plan by each participant, provided however, that unanimity among the participants developing the plan shall not be required for the commission to approve the plan; (g) The extent to which the plan provides programs which are available, affordable, and useful to all customers; and (h) Next-generation residential utility meters that can provide residents with amount of current utility usage, its cost, and can be capable of being read by the utility either remotely or from the exterior of the home.[6]

II. <u>Overall effectiveness of current DSM programs in the state</u>

Indiana's energy efficiency programs have been effective in achieving energy savings on a cost-effective basis, but going forward, it will take significantly more money to achieve increased energy efficiency savings. Much of the "low hanging fruit" has arguably already been harvested, plus energy efficiency is increasing due to changing building codes and appliance efficiency standards.

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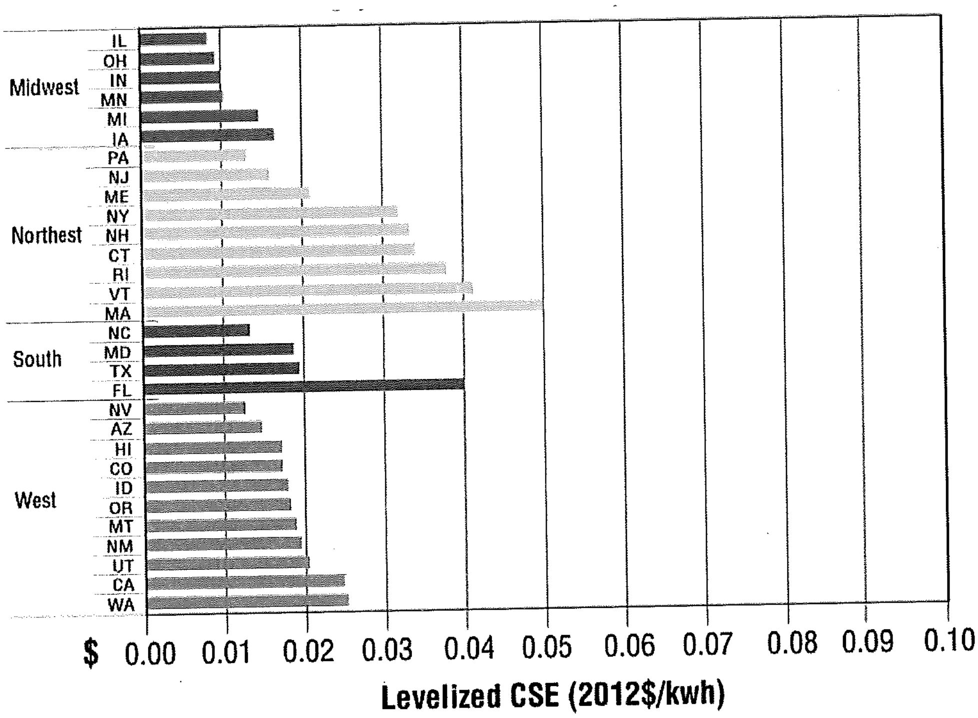
[6] Kentucky Revised Statutes, Sec. 278.285. (Emphasis added.)

To date, the Utilities' energy efficiency programs have achieved significant energy savings. From 2010 through 2013 alone, Indiana's energy efficiency programs saved 1,740,047 MWHs (gross), a 2.68% energy savings over a 2009 baseline. During this same timeframe, Indiana utilities incurred over $230 million for energy efficiency program expenditures.

As of 2012, Indiana fared relatively well in a state-by-state comparison of cost per kWh of achieved energy savings:[7]



However, Indiana's positive cost-effectiveness position will almost surely erode in the future if overly aggressive – and expensive – energy efficiency goals and programs are mandated. In its report (based on 2012 data), Lawrence Berkeley National Laboratory ("LBNL") notes interesting differences in the regional breakdown of lifetime energy savings compared to expenditures. For instance, Midwest programs reported around 20% more forecast savings on $1 billion in spending than the savings forecast for

[7] "The Program Administrator Cost of Saved Energy for Utility Customer-Funded Energy Efficiency Programs" by Megan A. Billingsley, et al. (March 2014) Figure 3-16 at P. 37, viewable at: http://emp.lbl.gov/sites/all/files/lbnl-6595e.pdf.

Northeast programs' $1.9 billion in spending. LBNL suggests that several factors may factor into the Midwest's position, most notably the relative newness of energy efficiency programs or efficiency building codes across the region, which allow states to achieve significant savings from low-cost measures. Compare this trend to the Northeast, where states have been consistently running efficiency programs for years and have well-established savings requirements. (In addition, higher labor costs in the Northeast may have factored into higher cost of saving energy.)[8] The Northeast's significantly higher cost of saving energy is likely to be Indiana's future if overly aggressive mandates are required. For example, if the Utilities were to stay on the same course as the 2009 Phase II DSM Order, Indiana's energy efficiency expenditures would increase significantly: a report commissioned by the DSMCC estimated that utility customers would be responsible for over $1.2 billion from 2015 to 2019 in just program expenditures to attempt to meet the Phase II Order's goals.[9]

Increasingly stringent building codes and appliance efficiency standards also suggest that the cost of utility-sponsored energy efficiency will rise, while the volume of "naturally occurring" energy efficiency will increase. Since the Commission's Phase II Order, aggressive new appliance efficiency standards and building codes have been promulgated and/or implemented, and these new standards and codes are expected to achieve significant energy efficiency savings independent of utility-sponsored energy efficiency programs. The Edison Foundation estimates that these new standards and codes will result in a minimum of approximately 2.5% in annual energy savings by 2020, compared to a baseline energy usage from 2009.[10] Similarly, ACEEE estimates that these new standards will result in approximately 2.3% in annual energy savings by 2020.[11] These

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[8] *Id.* at P. 45.

[9] "Indiana DSMCC Core Portfolio Report", submitted in IURC Cause No. 42693-S1 (June 19, 2013).

[10] The Edison Foundation, *"Assessment of Electricity Savings in the U.S. Achievable through New Appliance/Equipment Efficiency Standards and Building Efficiency Codes (2010 - 2020)."*

[11] American Council for an Energy Efficiency Economy, "Ka-BOOM! The Power of Appliance Standards: *Opportunities for New Federal Appliance and Equipment Standards*," July 2009.

are energy savings that, but for these new standards and codes, much of which would likely have been achieved by utility-sponsored energy efficiency. These new standards and codes will make incremental energy efficiency savings from utility programs both more difficult and more costly to achieve.[12]

Bottom line, while energy efficiency can play a meaningful and cost-effective role in utility resource planning, the costs, cost-effectiveness, and rate impacts (including cross-subsidization) associated with energy efficiency must be taken into consideration.

III. Recommended Improvements

> ***Circumstances have changed since the issuance of the Commission's Phase II DSM Order. Not only are there new appliance efficiency standards and building codes being implemented, energy efficiency program costs are increasing, and electric demand has remained essentially flat. As a result, the Utilities recommend several improvements for Indiana utility sponsored energy efficiency programs. First, eliminate arbitrary, across-the-board savings goals, in favor of "bottoms up," utility-specific IRP assessments. Second, recognize impacts from changing building codes and appliance efficiency standards. Third, consider rate impacts associated with energy efficiency programs. Fourth, require all Indiana retail electric utilities (not just jurisdictional utilities) to offer comprehensive energy efficiency programs to customers. Fifth, eliminate any mandates to utilize third party administrators to deliver utilities' programs. Finally, consider demand response as well as energy efficiency.***

Since the IURC's issuance of its 2009 Phase II DSM Order, a number of things have changed that make reconsideration of the IURC's EE framework reasonable and necessary: (1) aggressive new appliance energy standards and building codes; (2) flat demand for electricity; (3) cost-effectiveness challenges; (4) rate impact concerns; (5) changing regional and national EE landscape; and (6) increasing need for demand response.

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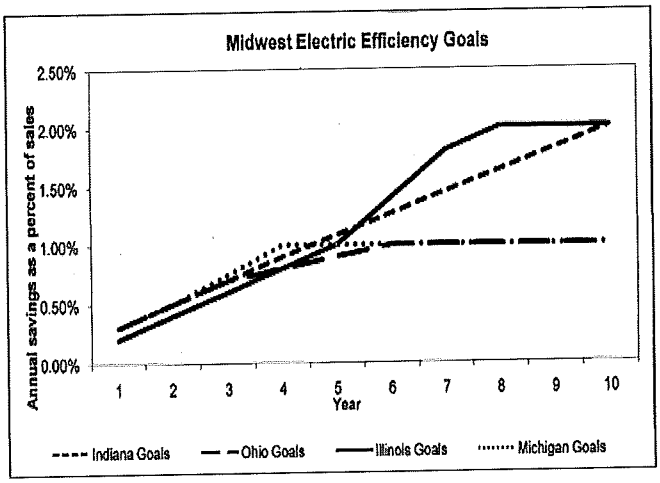
[12] See articles cited in footnotes 10 and 11, *supra*.

a. Eliminate "one size fits all" energy efficiency savings goals

In 2009, the Commission's Phase II Order mandated specific energy savings goals for Indiana's jurisdictional utilities. In creating these goals, the Commission gave consideration to the surrounding states of Illinois, Michigan and Ohio's energy efficiency goals. The Commission developed aggressive goals, goals that today are even more aggressive than those of surrounding states.



Indiana's goals, per the Phase II DSM Order:

2010 - 0.3%
2011 - 0.5%
2012 - 0.7%
2013 - 0.9%
2014 - 1.1%
2015 - 1.3%
2016 - 1.5%
2017 - 1.7%
2018 - 1.9%
2019 - 2.0%

*Total cumulative energy savings reduction of 11.9% reduction from 2010 to 2019.[13]

Although the Commission concluded in 2009 that Indiana was lagging behind other states in terms of EE, a current review indicates that, had the Phase II savings goals remained in place, Indiana's EE goals would have been slightly above the midpoint among the states that have energy efficiency resource standards. (Attached as Exhibit A is the 2013 ACEEE scorecard for Indiana, ranking it 27th in terms of energy efficiency.) Moreover, a number of states have recently reined in their EE program offerings, due to concerns about costs and rate impacts.[14]

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[13] Chart and numbers taken from *In the Matter of the Commission's Investigation*, Phase II Order, IURC Cause No. 42693 (Dec. 9, 2009) (hereinafter referred to as the "Phase II Order") at p. 31.

[14] *See* fn 24, *infra*.

These "one size fits all" goals ignore the fact that Indiana utilities possess different needs, different avoided costs, and different customer bases. A utility that does not have a need for additional capacity will (and should) approach energy efficiency differently than a utility who identifies a need for additional capacity. Similarly, a utility with a large industrial customer base will (and should) approach energy efficiency program design differently than will a primarily rural utility. In order to optimize energy efficiency, Indiana should focus on an individual utility's IRP, and energy efficiency programs that fit well into that individual IRP. For example, a utility that must replace retiring generation with a new baseload plant will invest hundreds of millions in such a plant and those costs will be recovered from customers. While the utility may decide it makes sense to continue sponsoring DSM programs, the reasonable level of costs to be recovered at the same time a large plant is reflected in customer rates should at least be considered. Mandated goals remove the possibility of any such considerations. Again, the IRP planning process represents the best opportunity to identify future capacity and energy needs, and to identify the optimal mix of supply- and demand-side resources to meet those needs in a cost effective manner.

b. <u>Consider rate impacts of utility-sponsored energy efficiency programs when assessing cost-effectiveness</u>

The Commission's DSM rules[15] generally require a utility to demonstrate the cost-effectiveness of proposed energy efficiency programs by means of the following tests: (1) participant test; (2) ratepayer impact measure test; (3) utility cost test; (4) total resource cost test; and (5) other reasonable tests accepted by the Commission. In practice, since 2009, the TRC test has informally been utilized in most cases to determine whether or not specific energy efficiency programs should be implemented. The Utilities submit that all of these tests – Participant, RIM, Utility Cost, and TRC -- should be considered, as all tests emphasize different and important stakeholder

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[15] 170 IAC 4-8-1.

perspectives, with primary emphasis given to the Utility Cost Test because that test is most similar to utility IRP analyses.

The Total Resource Cost (TRC) test examines efficiency from the viewpoint of an entire service territory. This test compares the program benefits of avoided supply costs to costs for administering a program and the cost of upgrading equipment. When a program passes the TRC test, this indicates total resource costs will drop, and the total cost of energy services on average will fall. In the TRC test, program rebates or incentives to customers are treated as transfer payments rather than costs to the utility.

The Utility Cost Test (UCT), also known as the Program Administrator Cost Test (PACT), measures cost-effectiveness from the viewpoint of the sponsoring utility or program administrator. If avoided supply costs exceed costs incurred by the program administrator, average costs decrease. The UCT is most analogous to utility IRP analyses.

The Ratepayer Impact Measure (RIM) test considers the viewpoint of a utility's customers as a whole, including non-participants, measuring distributional impacts of conservation programs. The test measures what happens to average price levels due to changes in utility revenues and operating costs caused by a program. A benefit/cost ratio less than 1.0 indicates the program will influence prices upward for all customers. For a program passing the TRC but failing the RIM, average prices will increase, resulting in higher energy service costs for customers not participating in the program. As noted by the "Stratton Report" which the Commission discussed in its Phase II Order,[16] the RIM Test is one of the most restrictive cost-effectiveness tests, and utilities implementing it tend to have fewer energy efficiency program offerings than utilities that employ a variety of benefit-cost tests, such as the Total Resource Cost Test, the Utility Cost Test, and the Participant Cost Test.[17]

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[16] Phase II Order at p. 28.

[17] *Id.*

The Participant Cost Test (PCT) measures benefits and costs to customers participating in DSM programs. The test compares bill savings against incremental costs of the efficient equipment. It measures a program's economic attractiveness to customers, and can be used to set rebate levels and forecast participation.

Below is an excerpt of a table from the California DSM Standard Practice Manual, for ease of reference:[18]

Test	Acronym	Key Question Answered	Summary Approach
Participant cost test	PCT	Will the participants benefit over the measure life?	Comparison of costs and benefits of the customer installing the measure
Program administrator cost test Also known as the Utility Cost Test	PACT or UCT	Will utility bills increase?	Comparison of program administrator costs to supply-side resource costs
Ratepayer impact measure	RIM	Will utility rates increase?	Comparison of administrator costs and utility bill reductions to supply-side resource costs
Total resource cost test	TRC	Will the total costs of energy in the utility service territory decrease?	Comparison of program administrator and customer costs to utility resource savings

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects

Several legislatures, commissions, utilities, and scholars have debated whether the TRC is the best test to use to determine cost-effectiveness of energy efficiency programs. One such group of scholars presented their study to the Maryland Commission asking, "Is it Time to Ditch the TRC?"[19] TRC has been regulators' principal

[18] National Action Plan for Energy Efficiency (2008). *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers*. Energy and Environmental Economics, Inc. and Regulatory Assistance Project. Viewable at: http://www.epa.gov/cleanenergy/documents/suca/cost-effectiveness.pdf at P. 20 (Note that the Societal Cost Test was removed from the chart.)

[19] Chris Neme, Marty Kushler, *American Council for an Energy-Efficient Economy, "Is it Time to Ditch the TRC? Examining Concerns with Current Practice in Benefit-Cost Analysis"* Viewable at: http://www.google.com/url?sa=t&rct=j&q=&esrc=s&frm=1&source=web&cd=4&ved=0CEIQFjAD&url=http%3A%2F%2Fenergy.maryland.gov%2Fempower3%2Fdocuments%2FACEEEreferencestudy-NemeandKushlerSS10_Panel5_Paper06.pdf&ei=3pVJUouuBeGNygGxuoHICw&usg=AFQjCNE9KuvbDBwFblBBe1XVD9LztOpJwA&sig2=3jpaD2Zgo1u_Adgtj4wt8Q (last viewed: 09-29-2013).

test for assessing energy efficiency programs cost-effectiveness and approving utility funding for the past two decades; however, the TRC as commonly applied today has fundamental problems.[20] With the use of the TRC, all that is considered germane is the purchase price to the utility for the resource. As Chris Meme and Marty Kushler noted, "[w]hile there are other venues (*e.g.*, public policy modeling and planning) where including a TRC perspective is still helpful, we believe it is time to emphasize the Program Administrator Cost Test [previously known as the Utility Cost Test] when making utility system resource decisions."[21] They concluded their whitepaper by noting that:

> We believe it is clear that the TRC, as currently applied, has significant flaws. Because of the asymmetrical application of the TRC test to energy efficiency resources, but not other utility resource options, efficiency resources are systematically disadvantaged. While historically this has had a rather limited practical impact (because energy efficiency programs have tended to pass both the TRC and PACT[/UCT]), that situation is beginning to change. As we move into an era of greatly expanded energy efficiency objectives, this additional burden for energy efficiency programs will likely result in substantially less energy savings being realized than if we were truly pursuing all cost-effective energy efficiency. (...) Given the options before us, switching from reliance on the TRC to the PACT[/UCT] appears the best way to address the problem both comprehensively enough and expeditiously.[22]

The Commission when evaluating energy efficiency programs should consider all of these tests (Participant, Utility Cost, RIM, and TRC), with an emphasis on the UCT, but also taking into consideration the TRC test, as well as the RIM test as a proxy for considering rate impacts.[23] Note that other states, in various ways, take rate impacts into consideration in the context of utility-sponsored energy efficiency programs.[24]

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[20] *Id.*

[21] *Id.* at p. 5-299.

[22] *Id.* at p. 5-309.

[23] The Utilities recognize that certain programs should not be required to pass cost-effectiveness tests in order to be implemented. For example, programs such as general education programs do not lend themselves to cost-effectiveness analyses. Programs targeted to low-income customers often do not pass cost-effectiveness tests but this set of customers should not be ignored when it comes to providing

c. Explicitly take into account changes in building codes and appliance efficiency standards

According to the U.S. Energy Department, by 2027 widespread use of LED bulbs could save the equivalent energy produced by 44 large power plants.[25] Through implementation of new federally mandated appliance standards, by 2025 it is expected that Indiana will have saved 5,027 GWh of electricity.[26] These are positive developments; however, these developments make utility-sponsored energy efficiency more difficult and more expensive to achieve. Changes such as these should be taken

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customers with options to reduce their energy usage and their energy bills. And new programs may need some cost-effectiveness flexibility when ramping up.

[24] For example, several states have implemented spending caps on their energy efficiency Programs, including:

- Illinois has a cost cap of around 2% of the amount paid per kWh (with ramp ups with incremental increase in savings goals).
- Michigan has a cost cap of 2.0% of total retail sales revenues for the 2 years preceding 2012 and each year thereafter.
- Minnesota has a cost cap of 0.5 percent for gas, and 1.5 percent for electric of its gross operating revenues from service provided in the state.
- New Mexico has a cost cap with program costs not to exceed 3% of customer bills, or $75,000 per customer per calendar year, whichever is less.
- North Carolina has a cost cap of no more than $12.00 for residential accounts; $150 per Commercial account; and $10000 per Industrial account.
- Ohio's cost cap for each utility and company shall equal the product of three per cent multiplied by the sales supply amount. The sales supply amount is the product of the sales baseline multiplied by the generation supply dollar amount.
- Pennsylvania's energy efficiency measures cost-cap is 2% of the electric distribution company's total annual revenue as of December 31, 2006, excluding the cost of low-income usage reduction programs.
- Texas has a cost cap based on kWh and the customer class, which increases with the consumer price index.
- Wisconsin has a cost cap of 1.2 percent of operating revenues beginning in 2012.

[25] As reported by the Associated Press, viewable at: http://www.nola.com/business/index.ssf/2013/12/home_electricity_use_falls_to.html (December 31, 2013).

[26] Reported by the Appliance Awareness Standard Project; Viewable at: http://www.appliance-standards.org/sites/default/files/fedappl_in.pdf (last viewed June 4, 2014).

into account in determining the optimal amount and cost of utility-sponsored energy efficiency.[27]

d. Indiana energy efficiency requirements should apply to all retail electric utilities in the State

The Commission's July 28, 2004 investigation to review Demand Side Management issues named all jurisdictional electric and gas utilities within the State of Indiana as Respondents.[28] The Phase II Order that resulted from that investigation required all utilities that fall under the jurisdiction of the Commission to meet energy efficiency goals, including requiring those utilities to hire a third-party administrator to deliver the programs. This left non-jurisdictional customers without the required comprehensive offerings of energy efficiency programs, contrary to the Commission's stated goal of making energy efficiency programs available to all utility customers.[29] And, this left non-jurisdictional retail electric utilities with an arguable economic development advantage over jurisdictional utilities, in that the non-jurisdictional utilities

[27] Notably, several other states take changing building and appliance standards into account. For example, in Arizona "[a]n affected utility may count toward meeting the energy efficiency standard up to one-third of the energy savings resulting from energy efficiency building codes and up to one-third of the energy savings resulting from energy efficiency appliance standards if the energy savings are quantified and reported through a measurement and evaluation study undertaken by the affected utility, and the affected utility demonstrates and documents its efforts in support of the adoption or implementation of the energy efficiency building codes and appliance standards." The California Commission also recognizes resource savings resulting from the incorporation of energy efficiency measures into state building codes, and state and federal appliance standards (referred to as C&S advocacy). Investor-owned utilities are allowed to credit savings from C&S advocacy in measuring progress in achieving Energy efficiency goals. The utilities are given credit for 100% of the savings attributed to C&S advocacy work adjusted for compliance levels and naturally occurring market potential. Colorado and Massachusetts also allow for building codes and appliance standards to be taken into consideration, and Iowa recently adjusted some of their utilities' energy efficiency goals to account for new building codes. *See*: *In the matter of the application of Public Service Co.*, Colorado PUC Decision No. C11-0442; Docket No. 10A-554EG, 2011 Colo. PUC LEXIS 743 (Mar. 30, 2011.) *In re: Black Hills*, Iowa Utilities Board Docket No. EEP-08-3, 2009 Iowa PUC LEXIS 24 (Mar. 3, 2009). *Investigation by the DPU*, 2008 Mass. PUC LEXIS 29 (Aug. 22, 2008).

[28] *In the Matter of the Commission's Investigation*, IURC Cause No. 42693 (July 28, 2004).

[29] Phase II Order at P. 32. See also the January 13, 2014 Docket Entry in IURC Cause No. 42693 –S1, allowing Indiana Municipal Power Agency ("IMP A") to withdraw as an intervening party and ceasing its voluntary participation in the Core Demand Side Management Programs.

were not required to incur energy efficiency costs, lost revenues, or energy-efficiency-related rate increases.

e. <u>Indiana should not mandate the use of a statewide third party administrator</u>

The understanding that utilities' resource needs vary and therefore energy efficiency programs should not use a "one size fits all" approach leads to the issue of the use of a statewide third-party administrator ("TPA") to implement energy efficiency. Indiana has differing temporal climates near Lake Michigan versus down in Evansville; Indiana also has large cities, many small towns, and many rural areas. These differing landscapes lead to differing needs among the utilities. Certain energy efficiency programs work better in one utility's footprint than another. For example, 30% of Vectren's customers use electric heating, whereas less than 10% of NIPSCO's customers use electricity for heating, therefore Vectren might focus a greater allocation of energy efficiency dollars on conservation for electric heating than NIPSCO. Also, OPower, a provider of an energy efficiency behavioral program, gives customers a comparison of a particular customer's energy use as compared to others in the same neighborhood. The program has worked well to curb use in NIPSCO's territory, but not as well in Vectren's territory. A statewide TPA does not take into account the various needs of the different utilities, each with very different landscapes and customers.

Moreover, a statewide TPA creates administrative inefficiencies and extra costs, by inserting an additional layer of administration that is not needed. The Utilities already have internal administrative personnel and expertise to deliver EE programs, and the Utilities are subject to oversight board and/or regulatory supervision. The additional time, money and resources spent on the TPA administration and committees do not create sufficient value. While the Utilities are committed to continuing to involve stakeholders in the development of their EE programs, we do not believe a statewide TPA bureaucracy is necessary or efficient.

Utilities have the obligation to serve their customers, and utilities are held responsible for their service. Customers view their utilities as trusted experts when it comes to electricity, including energy efficiency. As a result, utilities should be allowed to design, implement and deliver their energy efficiency programs to their own customers, subject to appropriate regulatory oversight.

f. <u>There should be an increased focus on demand response</u>

Electric consumers use a relatively predictable minimum amount of power, known as the baseload. Sometimes, however, demand for electricity will rise, such as when air conditioners are used during the hottest time of the day. The usage may create a peak, and in certain circumstances, it may be more cost-effective for customers to reduce their demand ("demand response"), compared to the utility's cost of purchasing peak power. Demand response from commercial and industrial customers is also useful in reducing peak demand. In the aftermath of the 2009 DSM Phase II Order, Indiana's emphasis has been much more focused on energy efficiency than on demand response. The focus has been on reducing kWh energy, as opposed to reducing kW demand that could result in the deferral of new generating assets.

Further, due to the substantial retirements of coal-fired units in the near future due to environmental regulations, the Midwest region is expected to experience capacity reserve deficits. For example, MISO is projecting possible capacity reserve shortages of approximately 2 Gigawatts as early as the 2016 timeframe. PJM ran several shortfalls during the Polar Vortex in the winter of 2014. PJM is also projecting a decrease of its reserve margin of nearly 10 percent by June 2018, amid concerns that PJM's capacity market pricing will not incent needed new generation because of deregulation laws enacted in several states within the PJM region.

There are also other potential demand response programs related specifically to infrastructure, including automatic direct response systems that can sense impending demand load problems and divert or reduce power in strategic places, which helps to eliminate the potential of overloading the system and a potential power failure. Demand response could help reduce the need to build power plants to meet peak demand, and distribution system improvements. These further innovations in demand response should be considered alongside any energy efficiency programs. Moreover, cost-effective demand response programs generally have the advantage of mitigating, rather than exacerbating, rate impacts from demand-side management activities, because they do not create significant "lost revenues."

IV. <u>Ratemaking treatment for utility energy efficiency programs</u>

Indiana should allow timely recovery of program costs, lost revenues and performance incentives, in order to mitigate financial penalties a utility will suffer if it implements energy efficiency programs without these ratemaking mechanisms. In order to achieve the most cost-effective energy efficiency portfolios possible, appropriate ratemaking treatment, including program cost recovery, lost revenue recovery, and performance incentives, are imperative.

In order to encourage cost-effective energy efficiency programs, as a matter of policy regulators should allow for timely recovery of prudent program costs, lost revenues, and shareholder incentives. The importance of incorporating all three – program costs, lost revenues, and performance incentives – into rates has been repeatedly recognized by policymakers and state and federal governments. For example, the Commission's DSM Rules recognize the need to provide supportive regulation to place DSM on a more level playing field with utilities' supply-side resource options through the recovery of program costs, lost revenues and incentives. SEA 340 similarly recognizes that program costs, lost revenues, and incentives are appropriately included in rates. The Environmental Protection Agency's National Action Plan for Energy Efficiency and the National Energy Policy Act of 1992 both support the creation of incentives and the removal of financial or regulatory basis in order to promote the use of DSM, as does the federal Energy Independence and Security Act of 2007.[30] The Utilities believe it is imperative that this ratemaking treatment be available for energy

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[30] National Action Plan for Energy Efficiency. 15 U.S.C. §2621(d)(8); *see also* 15 U.S.C.§3203(b)(4) ("The rates allowed to be charged by a State regulated electric utility shall be such that the utility's investment in and expenditures for energy conservation, energy efficiency resources, and other demand side management measures are at least as profitable, giving appropriate consideration to income lost from reduced sales due to investments in and expenditures for conservation and efficiency, as its investments in and expenditures for construction of new generation, transmission, and distribution equipment.") *See also* section 532 of the Energy Independence and Security Act of 2007.

efficiency programs, on a consistent basis. To do otherwise would penalize utilities for implementing cost-effective energy efficiency programs, and would provide a serious disincentive to utilities to pursue such programs. Related to recovery of lost revenues and performance incentives, the Utilities remain committed to using independent third party evaluation, verification and measurement ("EM&V") of EE program savings.

The Utilities also believe that Indiana should consider other means of recovery of lost revenues, in addition to lost revenue rate adjustment mechanisms. For example, Indiana should consider approving "decoupling" and/or "straight fixed variable" rate designs. Such rate designs can be a key element of establishing a long term framework that supports use of DSM from a planning perspective. Recently, the Edison Electric Institute ("EEI") and the Natural Resource Defense Counsel ("NRDC") issued a joint statement directed at regulators urging the departure from existing volumetric based rate design that ties utility fixed cost recovery to energy sales in order to allow utilities to adapt to changing customer needs and environmental requirements while still maintaining reliable service. Elimination of a sales incentive removes a long standing obstacle to promotion of DSM by aligning utility and customer interests in selection of cost effective resource alternatives while maintaining the financial health of the utility in an environment of decreasing sales.

Decoupling allows a utility to separate its profits from its sale of energy. With decoupling, the rate of return is associated with meeting revenue targets, and rates are trued up or down to meet the target at the end of the adjustment period. This makes the utility indifferent to selling less of its product and improves the ability of energy efficiency and distributed generation to operate within the utility environment. Neighboring states, Minnesota, Michigan, Ohio, and Illinois all allow for decoupling, either through statute or by a commission order.[31]

[31] *See* Illinois Utility Commission decisions in *North Shore Gas* (Docket 07-241, 2008) and *Peoples Gas* (Docket 07-242, 2008); Michigan (Public Act 295 of 2008 (enrolled SB 213)); Minnesota (2008 § 216B.241); Ohio (ORC 4928:66(D)).

Alternatively, some states allow for straight fixed variable rate designs.[32] Straight fixed variable rate design is a particular type of decoupling mechanism, which segregates fixed costs, (*i.e.*, those costs which are incurred by the utility in order to be able to provide service, regardless of how much gas or electric energy is used) from those costs based on actual, variable total usage. Straight fixed variable rates remove the financial penalty that the utility realizes when customers take actions to reduce their energy consumption, and therefore promotes energy efficiency programs.

It is also important to emphasize that in Indiana currently, there is no interclass subsidization of energy efficiency program fees by one class for another. Any fees collected for energy savings produced by energy efficiency programs from residential rates go towards programs for residential customers, and likewise any fees collected for savings from energy efficiency programs from commercial and industrial customers go towards programs for commercial and industrial customers. The Utilities submit that this class-by-class allocation of energy savings related efficiency program costs should continue, and that minimization of cross-subsidization should be a goal.

V. <u>Indiana should allow for an opt-out whereby large electricity customers can decide not to participate in a DSM program, such as that included in SEA 340</u>

The Utilities believe that an opt out for large industrial customers, such as that contained in SEA 340, is reasonable and should be continued.

For a number of years, the Commission implemented its jurisdiction over utilities' energy efficiency activities via utility-specific orders, and in many cases, large commercial and industrial customers were not included in utility-sponsored EE programs.[33] It was not until the Phase II Order in 2009 that the Commission concluded

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[32] In Ohio a utility may apply to PUCO for approval of a revenue decoupling mechanism; gas utilities have been permitted to use straight-fixed-variable rate designs, determined on a case-by-case basis.

[33] *See, e.g., In re Petition of Indianapolis Power & Light Company for Approval of and Authority to Implement Demand Side Management Programs, and for Accounting and Ratemaking Treatment of Costs Incurred and Lost Revenues as a Result of Implementation of Demand Side Management Programs Approved by the Commission*, Cause No. 39672, 1993 Ind. PUC LEXIS 370 (IURC; Sept. 8, 1993). In 1991, pursuant to a settlement agreement entered into with intervenor groups and approved by the

that utilities must offer programs for all customer classes, and no customer or customer class could opt-out of the program. However, as the legislature has concluded through the development of Senate Enrolled Act 340, opt-out makes sense for large sophisticated industrial customers.

Industrial customers compete in national and global markets, customers often make their own investments to improve the energy efficiency of their unique industrial processes which are an essential component of their business model. Indeed, such customers have a natural incentive to cost-effectively reduce their energy costs via energy efficiency investments. Large industrial customers often hire their own energy consultants to assure that they are making optimal use of their energy to keep their energy costs down, and often evaluate energy efficient improvements with their own cost-benefit analysis as it relates to their unique businesses. Often they can increase energy efficiency more cost effectively with their own funds rather than relying on and paying for utility programs. This is the reason that only 184 out of 1098 customers with over 1 MW of load even participated in the energy efficiency Program, and often the participation benefit did not cover the cost of the program to the individual customer.[34]

Large energy consumers are also more likely to have unique manufacturing processes, which do not readily lend themselves to generic energy efficiency programs.

Further, the higher rates that industrial customers pay to participate in utility-sponsored programs reduce the funds available to the customer for investing in higher value projects that make the most sense in the customer's business situation. Forcing large industrial customers to participate in the utility's energy efficiency program provides a disincentive to large industrial customers to create their own customized energy efficiency solutions, and provides no reward to those who made the energy efficiency improvements before the 2009 Phase II Order. Actually, it punishes some

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Commission (Cause No. 38986),Duke Energy Indiana implemented its initial set of EE programs that targeted multiple end uses for all customer classes.

[34] Data represents five Indiana utilities: Duke Energy Indiana, Vectren Energy Delivery, Indianapolis Power & Light Company, Indiana Michigan Power Company, and Northern Indiana Public Service Company.

industrials who made their own energy efficiency investments prior to 2009, and who are being forced to subsidize the investments of their competitors.

With respect to an opt out provision, it is important to have a "bright line" cutoff, such as the "greater than 1 MW" cutoff included in SEA 340, which includes a diverse mix of customers including many industrial customers and some large commercial customers. Energy consumers of this size thus often have more sophisticated equipment and needs that will be better served by their own energy efficiency solutions than utility-sponsored programs.

Further, from the utility's perspective, the "greater than 1 MW" cutoff is a clear and distinct bright line that is easy to objectively administer. With that being said, other than for those rate schedules that allowed aggregation when SEA 340 went into effect[35], SEA 340 should not be changed to allow "aggregation" of more than one site. Allowing this would be contrary to the rationale for the 1 MW opt out – large, sophisticated energy users with unique energy needs. Cost of service principles generally disfavor aggregation, which is why only two customers in the entire state are currently allowed to aggregate load for the purposes of receiving service and those two customers are unique situations.[36] It does not cost the utility any less to serve a customer with multiple sites. Therefore, providing them a benefit of allowing aggregation of those smaller sites to reach the required 1 MW would not be fair to other customers who, if allowed to aggregate with other customers, could also reach the greater than 1 MW threshold. If that happens, whether it is customer aggregating multiple sites, or several customers adding their own sites together, the result is the same: the customers are no longer large, sophisticated energy users, which goes beyond the intention of the legislature. Indiana's aggregation policy should not change to allow customers to opt-

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[35] As approved by the Commission, NIPSCO has two rates, each with one customer: Rate 634-Rate for Electric Service, Industrial Power Service for Air Separation & Hydrogen Production Market Customers and Rate 644-Rate for Electric Service, Railroad Power Service, that permit aggregation of multiple delivery points.

[36] The customer receiving service under NIPSCO's Rate 634 has at least one meter at each of its sites that meet the required threshold of more than 1 MW of capacity. The customer taking service on Rate 644 is considered to be a railroad with "one continuous electric right of way," with seven of the eight meters independently meeting the capacity threshold.

out of energy efficiency. However, if a utility has a unique situation that would call for aggregation, the utility should be able to seek such approval from the Commission.

Even with allowing large industrial customers to opt-out of energy efficiency programs, SEA 340 should not be changed to eliminate the concept of recovery from opt out customers of "trailing costs" – to do so would result in a cost shift to remaining customers. Opt out customers should pay all costs that relate to programs implemented while they were program participants. These "trailing costs" include lost revenues relating to pre-opt-out implementation of program measures, as well as certain fixed costs that are part of the existing Third Party Administrator and Evaluation, Measurement and Verification contracts. Because the Commission ordered utilities to provide these programs to all customer classes, it would be unfair to now shift these costs to other customers who are not eligible to opt out. Moreover, some Indiana industrial customers have participated in the energy efficiency program, and have obtained a benefit from the result of that participation, which the utility may not have recovered in rates at the time the customer opts-out.

Respectfully submitted,

Duke Energy Indiana, Inc.

Indiana Michigan Power Company

Indianapolis Power & Light Company

Northern Indiana Public Service Company

Vectren Energy Delivery of Indiana, Inc.

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