BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of an Investigation into the Coordination of State and Federal Regulatory Policies for Facilitating the Deployment of all Cost-Effective Demand-Side Savings to Electric Customers of All Classess Consistent With the Public Interest	* * * * * *	File No. EW-2010-0187

INITIAL COMMENTS OF ENERNOC, INC.

Pursuant to the Missouri Public Service Commission's ("Commission") Order issued in the above-referenced file on January 5, 2010, and the Staff Report filed on January 27, 2010, EnerNOC, Inc. (EnerNOC) submits these initial comments and responses to questions presented in the Commission Order.

I. Correspondence and Contact Information

The following contact information may be used to direct all correspondence and service copies of documents in this investigation:

Kenneth D. Schisler
Sr. Director of Regulatory Affairs
EnerNOC, Inc.
101 Federal St., Suite 1100
Boston, MA 02110
kschisler@enernoc.com
410-745-8104

II. About EnerNOC

EnerNOC is a leading developer and provider of clean and intelligent power solutions to commercial, institutional, and industrial (C&I) end use customers, as well as electric power grid operators and utilities. EnerNOC's technology-enabled demand side response and energy management solutions help both customers and grid operators optimize the balance of electric supply and demand.

EnerNOC manages aggregated demand response resources across numerous C&I customer verticals, including, education, government, health care, hospitality, retailing, commercial real estate, agri-business, manufacturing, and more. EnerNOC currently manages over 3,550 MWs of demand response resources throughout North America and in the United Kingdom[1], and is the largest company of its kind in the world.

EnerNOC actively manages aggregated demand response resources participating in a broad variety of reliability-based programs, economic price-response programs, and ancillary services markets. EnerNOC is a direct market participant in ISO-New England, PJM Interconnection, New York ISO, and the Electric Reliability Council of Texas (ERCOT) wholesale electricity markets. In addition, EnerNOC provides demand-side management services through bilateral arrangements with utilities throughout North America, in both investor-owned and public power utility systems in the Tennessee Valley Authority Region, Arizona, California, Colorado, Florida, Idaho, Maryland, Vermont, and Washington. EnerNOC also provides demand-response services in open-market programs in Ontario, Canada and in the United Kingdom.

[1] As of December 31, 2009.

EnerNOC does not provide demand response services to Missouri utilities or directly bid demand response resources into the Southwest Power Pool (SPP) or Midwest ISO (MISO) wholesale markets at this time. However, EnerNOC provides energy efficiency services to Missouri customers and is interested in expanded clean energy business activities in Missouri. EnerNOC has also been actively involved in developing the rules for direct participation that have been submitted to FERC for approval through MISO's Demand Response Working Group (DRWG).

EnerNOC's energy efficiency offerings serve customers throughout North America, including Missouri. Energy efficiency services offered by EnerNOC include retro-commissioning and monitoring-based commissioning of commercial and institutional buildings. Both retro-commissioning and monitoring-based commissioning measures achieve energy savings by conducting extensive audits and analysis to ensure buildings are "tuned" to perform optimally. Although capital-based energy efficiency projects (such as upgrading an inefficient chiller) may be identified through commissioning efforts, most energy efficiency measures identified under retro-commissioning and monitoring-based commissioning are no-cost or low-cost improvements – such as adjusting set-points and schedules to better reflect system dynamics and occupancy characteristics. Retro-commissioning is typically a one-time or periodic effort, while monitoring-based commissioning uses technology to continuously monitor a building's performance.

Monitoring-based commissioning is a continuous process of evaluating data from numerous building-specific and external sources to identify and prevent wasted energy and improve building occupant comfort. Among other things, monitoring-based commissioning detects anomalies in customer energy consumption that lead to excursions from optimal energy efficiency.

For example, for a variety of reasons, a building's HVAC system can begin to operate sub-optimally, though the space being heated or cooled still feels comfortable. This wasted energy is difficult to detect. The HVAC system may heat and cool at the same time, fail to utilize either fresh or re-circulated air as appropriate, the system may be heating or cooling unoccupied spaces at night, or the HVAC equipment may turn on or off too frequently. In all above situations, the space being heated or cooled will feel comfortable when occupants are present, and the wasted energy is not obvious. Monitoring-based commissioning for energy efficiency detects these and other anomalies as they occur so that the matter can be addressed, energy is not wasted, and occupant comfort is optimally-maintained. Monitoring-based commissioning improves the persistence of energy efficiency efforts by ensuring that once implemented, energy-saving measures do not degrade over time.

III. EnerNOC's Interest in this Proceeding

EnerNOC offers its insights as a company that is a clean energy technology and demand side management services provider in nearly every region of North America under a variety of wholesale and retail market designs. EnerNOC is a third party Aggregator of Retail Customers (ARC) that is not affiliated with any distribution utility or load-serving entity. EnerNOC operates as a direct participant in many wholesale markets, through bilateral contracts with utilities in retail markets, and in hybrid wholesale-retail market structures. While not currently serving Missouri customers with demand response, we are very interested in doing so in a constructive regulatory environment for demand side management services that encourages innovation and seeks deployment of all cost-effective demand side resources.

IV. Brief Statement of Position

Retail customer participation in demand response provides benefits to participants and non-participants alike. Such benefits include enhanced system reliability, lower energy costs, improved system efficiency (higher load factor) and diversity of energy resources. Demand response can be successful and provide ratepayer benefits under a variety of models, including customer demand response participation that is aggregated directly into the wholesale market, or through retail programs, or a combination of a retail program that is designed to operate congruently with demand side resource participation in wholesale market.

The Federal Energy Regulatory Commission ("FERC") expressed strong support for the role demand response can play to improve the nation's wholesale electric markets:

> "Demand response can provide competitive pressure to reduce wholesale power prices; increases awareness of energy usage; provides for more efficient operation of markets; mitigates market power; enhances reliability, and in combination with certain new technologies, can support the use of renewable energy resources, distributed generation, and advanced metering."[2]

[2] 125 FERC ¶61,071 (October 17, 2008), FERC Order 719 at ¶16

As the Commission observed in its Order opening this investigation, a fundamental tenet of FERC Order 719 and 719-A[3] is reducing barriers to demand response in FERC jurisdictional wholesale markets in a manner that is fully consistent with state regulation.[4] These FERC orders require organized wholesale markets, including SPP and MISO, to modify their federal tariffs to allow ARCs to bid demand side resources into wholesale markets. However, in directing SPP and MISO to make these changes, FERC has made it clear that the requirements were subject to state law and policy.

As stated above, EnerNOC has been successful in increasing demand response activity under a variety of regulatory models. We do not have a position about whether the best means to achieve Missouri's policy objectives is through ARC's bidding demand resources directly into the wholesale markets or through another alternative such as ARCs working in concert with the state's utilities. The Commission has correctly recognized that the starting point for making an appropriate determination regarding wholesale market demand response activities of Missouri retail customers is not federal law or policy, but rather Missouri law and regulatory policies toward demand side management.[5] In our view, a determination as to whether ARCs should enroll customers directly in wholesale markets should be informed by an exploration of the best means to achieve Missouri's policy objectives.

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[3] 128 FERC ¶61,059 (July 16, 2009).
[4] FERC Order 719 at ¶¶155-156; FERC Order 719-A at ¶54.
[5] Commission Order in EW-2010-187 (January 6, 2010).

The Missouri Energy Efficiency Investment Act (MEEIA) enacted into state law a number of constructive provisions that have tremendous potential to stimulate significant growth of demand side management in the state. The law truly gives the Commission the tools necessary to fulfill the state policy objective of achieving all cost-effective demand side savings. EnerNOC is both confident and hopeful that the Commission will see tremendous value in leveraging the expertise of ARCs to help Missouri fulfill its policy goals.

EnerNOC recognizes that some utilities have successful demand response and programs. ARC participation in wholesale markets directly, or indirectly through a host utility, does not mean that successful utility programs will be harmed. When done correctly, ARC participation will augment successful utility demand response programs.

Experience demonstrates that ARCs can generally achieve greater levels of demand response participation from C&I customers than the utility acting alone. This is true for a variety of reasons. Achieving customer demand reductions is not generally the core competency of a utility. But it is, in many cases, the entire focus of ARCs, and it is their core competency. Unlike relatively homogenous residential loads, C&I loads vary widely across types of facilities. Effective C&I load curtailment strategies must be customized to each organization's specific operational requirements to avoid negatively impacting operations or occupant comfort. ARCs have specialized demand response expertise in specific industry verticals across a national footprint in numerous utility service territories. This expertise allows ARCs to better find customer load reduction capability that is reliable and will not damage customers' electricity consuming equipment. ARC site technicians work very closely with customer facilities managers to find load reduction capability and develop and test curtailment protocols that enable the customer to be successful in demand response.

Utilities, by contrast, are generally not accustomed to working with customers "behind the meter." Utilities often have interruptible programs available and they may promote them to customers, but they generally do not invest in dedicated personnel resources that are experienced in the specific industry to work with the customer to find curtailment capability that maximizes participation while minimizing negative impact on the customer's business. This extra effort can make the difference between whether or not a customer chooses to participate in a demand response program.

The regulation of utilities as monopoly franchises also carries with it a non-discriminatory obligation to serve customers. Utilities fulfill these requirements by offering service through public retail tariffs, or through special contracts approved by state commissions. This traditional regulatory paradigm makes it difficult for utilities to design demand response opportunities that can be attractive for all customers. Utilities seeking to offer demand response to customers generally make a generic tariff offering that may not work for large numbers of customers. This may be especially problematic for C&I customers whose load shapes are highly variable. This often results in demand response tariff opportunities that are undersubscribed or in which the demand response volume associated with the utility resource is lower than can be achieved through an ARC. In short, the reason for this is that a given customer's capabilities to respond do not always perfectly match the utility's "one-size-fits-all" tariff. ARCs can solve this problem by customizing contracts with customers to capture the value from each customer, and managing over- and under-performing demand resources like an insurance portfolio to ensure performance to committed levels. In this regard, many ARCs insulate customers from penalties that may be incurred due to under-performance or non-performance. Exposure to penalties, present in most utility-sponsored tariff-based programs, can be a strong deterrent to customer participation.

While mass marketing strategies can be effective for residential demand response programs, C&I customers usually require a more personalized sales approach. ARCs are typically very effective at marketing and selling demand response offerings to customers and can dedicate focused effort to the task of enrolling customers. Utility account executives, by contrast, typically have numerous utility offerings to discuss with customers. Depending on how internal goals are structured, a demand response program may not necessarily be "top priority" for an account manager. By contrast, an ARC is completely focused on effectively engaging customers to explain the program's benefits. This focus reduces the likelihood of under-enrollment. In addition, while utilities commonly have account managers assigned to their largest customers, smaller "non-managed" accounts present special challenges, since implementing a C&I demand response program requires direct contact with customers to assess demand response potential and enrollment into a program. ARCs are generally accustomed to approaching smaller "non-managed" accounts.

Finally, to be confident that C&I demand response programs will deliver verifiable capacity when dispatched, significant investments in technology and processes are required. Many ARCs have invested heavily in the technology and processes that enable reliable demand response participation. Building the requisite infrastructure for a large-scale program with hundreds if not thousands of C&I participants can cost millions of dollars. By partnering with an ARC, utilities and customers can leverage that company's existing investments in technology and process development. Many ARCs have built sophisticated "operations centers" that manage demand response resources on a real-time basis in much the same way that a utility control center manages conventional supply-side assets. A utility or grid operator is able to dispatch demand response events by simply sending a signal to the ARC's operations center, rather than to each participating customer. Once dispatched, many ARCs have the ability to remotely monitor and control a site's energy consumption in real time. This automation of some or all of the process of a demand response event takes the burden off facility staff during the demand response event and increases customer acceptance and success in demand response. In addition, because the ARC has real time visibility into customer consumption activities, ARCs are able to perform intra-event management or "coaching" to customers who, for a variety of reasons, may not be reducing consumption as expected.

The best result for Missouri, and the state policy goal that is now codified in law, is one that maximizes the amount of cost-effective demand side resource participation by customers. To achieve these results, Missouri should determine how its regulatory policies can leverage the expertise of ARCs to work with the state's utilities and customers. ARCs serve a valuable role in the development and delivery of demand response services. ARCs can cost-effectively achieve higher demand response participation than utilities acting alone by:

- Utilizing deep industry-specific knowledge to customize “behind the meter” demand response strategies for participating customers.
- Flexibly contracting with customers to enable participation that works within a customer’s capabilities and constraints, rather than through a one-size-fits-all tariff.
- Dedicating sales and marketing resources to provide needed outreach to educate and enroll customers into a demand response program.
- Deploying sophisticated technology and processes to ensure reliable delivery of demand response capacity.

V. Responses to Commission Questions

1. Does the term “energy efficiency” include shifting demand to off-peak periods? See Section 393.1124.2(4). Does “modify net consumption” as used in Section 393.1124.2(3) include shifting demand to off peak periods? See Section 393.1124.2(2).

Since the statute provided a separate definition for demand response that includes shifting demand to off-peak periods, it appears that the Legislature did not intend for the term energy efficiency to include shifting demand to off-peak periods. The term “modify net consumption” in the statute should be read to include shifting demand to off-peak periods.

Energy efficiency and demand response are two ends of a continuum of demand side management activities. Energy efficiency generally means using less energy, without regard to system conditions. Demand response involves reducing demand at a specific time, which may include a peak system condition or as a dispatch of operating reserves. Energy efficiency is often distinguished from demand response in that energy efficiency is not "dispatchable," while demand response is dispatchable. There are demand attributes to energy efficiency to the extent energy efficiency reductions coincide with system peaks. There are also energy efficiency and conservation benefits with demand response inasmuch as demand response strategies result in consuming less electricity overall, and consumer awareness of demand management generally makes customers more efficient users of energy.

There are important synergies between energy efficiency and demand response strategies, and well-designed resource planning for demand resources will pursue both simultaneously. Energy efficiency without demand response perpetuates an inefficient system overall with a low load factor and high critical peaks; the grid still needs to be built to accommodate levels of system demand that occur only a very few hours of the year. Demand response without energy efficiency reduces the inefficient deployment of capital to serve high system peaks or operating reserve needs of the grid, but does not lead to sufficient energy conservation at all other hours of the year.

2. What does "load management" as used in Section 393.1124.2(3) mean?

Load management is generally synonymous with demand response.

3. What is "demand savings"? How should "demand savings" be determined? See Section 393.1124.4.

"Demand savings" should be read to include both energy efficiency and demand response. In other words, demand savings should include both kWh and kW savings. Demand savings can come from energy conservation, or reducing consumption of energy below what would have occurred without the demand side measure. Demand savings can also mean customer actions taken to avoid the use of high price energy or using a demand response resource to meet the balancing/supply needs of the grid in place of a generation resource (e.g. using demand response as a reliability backstop or using demand response in place of quick ramp generation to provide ancillary services).

4. How should "energy savings" be determined? See Section 393.1124.4. Should there be a regular, standard process for determining whether a utility program achieves "cost-effective measurable and verifiable efficiency savings"? See Section 393.1124.3(3). If "yes," what should be that regular, standard process?

There are a number of standards for measurement and verification of energy efficiency resources in use throughout the United States. There is not a single standard, but several have attracted a significant following. A fair discussion of the various standards for measurement and verification would require an extensive response, but as part of its investigation the Commission should further explore the best means to suit Missouri policy objectives. The Lawrence Berkeley National Laboratory has done important work analyzing various methods in use, and should be considered a resource going forward.

The various measurement and verifications methods in use generally consider the persistence of energy savings, or the "measured life" of various efficiency measures, and include measurement and verification protocols to ensure efficiency savings are realized and measured in a consistent fashion.

Demand response energy savings should be measured against a customer baseline (CBL) that recreates what customer consumption would have been without the demand response action. There are also various CBL methods in use in wholesale and retail market demand response programs throughout the United States that can be explored for use in Missouri.

A well-designed CBL includes elements that address at least three key criteria: accuracy, integrity, and administrability. The CBL needs to accurately measure the load reduction due to customer demand response measures. To ensure integrity, a CBL should include protections against baseline gaming that would otherwise enable a customer to claim credit for demand reductions from normal operations. For example, if the CBL mechanism can be manipulated to inflate the customer's baseline from normal operations, normal operations during demand response events may appear as load reductions. Finally, the administrability element relates to a need to design a CBL method that is easily understood and can be easily calculated by the customer and the program sponsor.

5. What is meant by the term(s) "rate design modifications" / "rate design modification" as it appears in Section 393.1124.5?

Utilities rate designs may need to be modified to achieve the policy objectives of the MEEIA to value demand side resources equal to supply side investment. Attached to this filing at Appendix A is whitepaper published by Edison Foundation Institute for

Electric Efficiency that evaluates various rate design modifications in-use throughout the United States.

6. How does a "customer" "notify" the "electric corporation" that the customer elects not to participate in demand-side measures offered by an "electrical corporation"? See Section 393.1124.7.

Pursuant to the statute, utilities will need to develop procedures for customers electing to "opt-out" of utility demand side management charges by demonstrating independent compliance with the requirements of the statute.

7. Is there any significance to the fact that the term "electric corporation" appears in SB 376 in addition to the term "electrical corporation," and the term "electric corporation" is not a defined term in Section 386.020?

EnerNOC cannot discern evidence of legislative intent to distinguish between "electric corporation" and "electrical corporation" in state law.

8. What is the definition of the term "customer" as that term is used in SB 376?

In the absence of a definition of customer in the statute, the term should be given its meaning in ordinary usage. The term "customer" in the statute should be read to mean a retail electric customer or end user of electric energy.

9. What is meant by the term "corporation-specific settlements" which appears in Section 393.1124.11?

The MEEIA authorizes the Commission to enter into utility-specific demand side programs, through settlement or otherwise, as opposed to a requirement that all utilities have the same programs.

10. How does, or how should, an electrical corporation propose a demand-side program pursuant to Section 393.1124? See Section 393.1124.4. How does, or should, the Commission approve demand-side programs proposed pursuant to Section 393.1124? See Section 393.1124.4.

These issues should be explored in the context of the investigation to determine the appropriate mechanisms for proposing, approving, and implementing demand side programs consistent with the MEEIA. One approach may be to require jurisdictional utilities to develop comprehensive demand side management plans focused on achieving all cost effective demand savings. The net result of these plans can then be fed into utility integrated resource planning processes.

11. How should the determination be made whether a demand-side program is beneficial to all customers in a customer class regardless of whether the program is utilized by all customers? See Section 393.1124.4.

Properly designed energy efficiency and demand response programs provide social benefits to all customers in addition to the private benefits accruing to program participants. The MEEIA authorizes the Commission to utilize several cost-effectiveness tests, with a preference for the Total Resource Cost (TRC) test. The TRC test is used in many jurisdictions to determine whether a demand-side program or portfolio of programs is cost-effective, and therefore beneficial to pursue.

12. Does any Missouri statute, case law, or regulation prohibit or restrict electric utility customers from participating directly or indirectly through aggregator of retail customers (ARCs) in demand response bidding programs, as discussed in FERC's Order Nos. 719 and 719-A?

EnerNOC is aware of no such prohibition in any statute, case law or regulation that would prohibit utility customers from participating directly or indirectly through

ARCs in wholesale market demand response. ARCs typically do not sell electric energy, and as such are not typically regulated as utilities under state law. See Missouri Revised Statutes, §393.010. FERC has recently issued an Order confirming that demand response is considered a service affecting wholesale rates, and not a sale of electric energy. Accordingly, a company acting as an ARC that is not also involved in the purchase and sale of energy is not a utility under the Federal Power Act.[6]

13. Does a single retail customer or an ARC act as a public utility subject to MoPSC regulation under the Missouri statute, case law, or regulation if it bids demand response into SPP's or MISO's organized energy market?

See response to question 12, above. Federal law and most state laws do not treat ARCs as subject to regulation as public utilities. That said, even absent regulation as public utilities, states are free to adopt regulatory requirements applicable to ARCs.

14. Does the right to furnish retail electric service under Section 393.170 give a certificated utility an exclusive right to "benefit" from demand response activities of its retail customers either directly or indirectly through an ARC?

To the extent that ARCs may be permitted to operate without being considered public utilities, there would appear to be no requirement that utilities have an exclusive right to benefit from demand response activities.

15. How would a certificated utility and its other retail customers be affected if a single retail customer or an ARC bid demand response directly into SPP's or MISO's organized energy market?

Direct participation of single retail customers or ARCs in SPP's or MISO's organized energy market will lower the wholesale cost of electricity. This is so because

[6] 130 FERC ¶61,031, FERC Docket Nos. ER09-1307-000 and ER09-1307-001 (January 19, 2010).

any demand response resource that clears in the market does so by displacing the next highest-price generation resource in the queue for security-constrained economic merit order dispatch. As a result, all customers will benefit by a lower, locational-marginal price (LMP) than if DR had not participated in the market.

When wholesale market rules are properly aligned, wholesale market participation by ARCs or any other market participant will not harm load serving entities (LSEs) and utilities. In fact, utilities/LSEs should enjoy the social benefits of increased demand response participation induced into the wholesale market by ARCs, including all of the benefits described in the block quote from FERC Order 719 quoted above at page 3 of these comments. If utilities/LSEs assert that their interests are not aligned to at least ensure that they are not harmed, there are flaws in the wholesale market that need to be rectified. Utilities/LSEs should direct any such concerns to FERC and to MISO and SPP to ensure that they are not harmed by activities of ARCs.

16. What would be the effect on utility rate design if a single retail customer or an ARC bids demand response directly into SPP's or MISO's organized energy market?

This question is directed at utilities.

17. What would be the effect on utility revenue collection if a single retail customer or an ARC bids demand response directly into SPP's or MISO's organized energy market?

Lost revenues from lost throughput to the utility from demand response should be mitigated or completely offset by the lower cost to serve load.

18. How would a utility's long-term load forecasting process change if a single retail customer or an ARC bids demand response directly into SPP's or MISO's organized energy market?

EnerNOC agrees that it is vitally important to include demand response in utility resource and load planning. It will be difficult to ascribe a determinative value at this point, due to the fact that direct participation in the MISO and SPP markets is at its infancy. However, that does not mean that an appropriate value for demand response resources should be zero either. Over time, with more experience, the ability to incorporate and plan for demand response will be based upon historical experience.

To the extent ARCs provide demand response services under contract to the utility, the utility has the opportunity to apply resource adequacy credits from those services toward its planning reserve margin (PRM). The utilities may also claim capacity associated with their DR-administered programs. If an ARC's DR resources qualify as a planning reserve resource in MISO and SPP, the ARC would receive the capacity value associated with that resource. The ARC could sell the capacity to a willing buyer, including a utility. The capacity purchased from an ARC would count toward a utility PRM the same as capacity purchased from a generator.

19. How would utility's budgeting process change if a single retail customer or an ARC bids demand response directly into SPP's or MISO's organized energy market?

This question is directed at utilities.

20. Are there any other consequences of allowing participation in demand response programs by a single retail customer or an ARC?

As stated by FERC, ARCs in Missouri would improve system reliability. Demand response resources take considerably less time to bring on line in comparison to building a new generation resource. Demand response can be dispatched for a variety of reasons to include system or local reliability and in response to wholesale market price signals. Demand response can be a capacity resource, provide energy and ancillary services. EnerNOC has demand response contracts with utilities that can be triggered for various reasons set forth in bilateral contracts.

Demand response resources can be available to the wholesale market as well as being available for dispatch by the utility. Demand response resources can be triggered for relieving peak demand, as a replacement for peaking power, or for local distribution or transmission emergencies in order to prevent outages. The flexibility with which the resource can be dispatched, enhances system and local reliability. In addition, demand response resources that are capable of providing reserves have a quick-response capability, which is also beneficial for system reliability relative to generation that may not have quick-start capabilities.

21. How would customers' demand rates be estimated if a single retail customer or an ARC bids demand response directly into SPP's or MISO's organized energy market?

This question is directed at utilities.

22. How would demand sales be transacted from an operation standpoint if a single retail customer or an ARC bids demand response into SPP's or MISO's organized energy market?

The specific answers to these questions are best addressed to SPP and MISO. Both SPP and MISO have pending matters before the FERC that are addressed at precisely this question.

23. Would existing or planned demand response programs, and the costs associated with implementation of these programs, be undermined or cause a loss in benefits to retail ratepayers if a single retail customer or an ARC bids demand response directly into SPP's or MISO's organized energy market?

The answer to this question should be no. To the extent that utilities perceive there are inconsistencies between wholesale and retail market participation, these questions should be informed through this investigation.

24. If the MoPSC has the authority to do so, what conditions would the MoPSC place on a single retail customer or an ARC if its bids demand response directly into SPP's or MISO's organized energy market?

State regulators, or more exactly, the relevant electric retail regulatory authority, have the ultimate power to permit or deny retail customer participation of demand response in wholesale markets. Reasonable conditions being explored by states and regulators throughout the country are ensuring compliance with state consumer protection laws and collection of relevant state taxes.

Wholesale markets typically impose qualification requirements upon ARCs as market participants to ensure that companies have the competency and financial ability to fulfill market obligations. In addition, the wholesale markets typically impose financial assurance or collateral requirements to protect market participants from financial exposure. Many states have deemed such requirements as sufficient to ensure that ARCs providing demand response services in wholesale markets are qualified. To the extent state regulators believe more regulation is necessary, states are free to impose additional regulation upon ARCs.

25. How are efforts to encourage demand response by MoPSC jurisdictional electric utilities implicated if a single retail customer or an ARC bids demand response directly in SPP's or MISO's organized energy market?

Wholesale markets should be properly viewed as a facilitator of improving efficiency and commerce for the benefit of the retail customers, rather than a barrier. There is no reason that ARC-provisioned DR and utility DSM programs cannot coexist. In fact, in nearly every market in which EnerNOC provides service, either under contract to the utility or directly into wholesale markets, the utility is also offering demand response and energy efficiency services. EnerNOC believes that direct participation of ARC resources can be included in a menu of options for customers without disruption to utility programs, as long as the ARC activities are coordinated with the utility, as is currently reflected in the MISO's October 2 Filing to FERC.

26. How are efforts to encourage energy efficiency programs by MoPSC jurisdictional electric utilities implicated if a single retail customer or an ARC bids demand response directly into SPP's or MISO's organized energy market?

EnerNOC does not believe that increasing the opportunity for demand response in Missouri will have a deleterious effect on efforts to encourage utility energy efficiency programs.

While demand response and energy efficiency are largely compatible, they employ different tactics and produce different results. In fact, energy efficiency measures are designed to reduce overall consumption of electricity (kWh-basis), with some resulting benefit to peak demand, demand response is designed to blunt peak requirements (kW-basis) with some ancillary benefit to reducing consumption. While both are important objectives, they achieve different results and are not necessarily interchangeable. Therefore, increasing DR opportunities should not affect the utilities' ability to meet the EE goals.

In general, ARC participation in MISO and SPP DR programs should have little impact on existing utility energy efficiency and conservation improvement programs for the reasons stated above. EnerNOC has seen a positive impact on energy efficiency from participation in demand response programs. That is, some C&I facilities have used the demand response payments they receive from EnerNOC as "seed corn" tofund further investment in energy efficient equipment upgrades. Thus in some cases demand response payments are recycled to buy ongoing energy efficiency.

Kenneth D. Schisler

Kenneth D. Schisler
Senior Director, Regulatory Affairs
EnerNOC, Inc.
101 Federal Street, Suite 1100
Boston, MA 02110
kschisler@enernoc.com
410-745-8104

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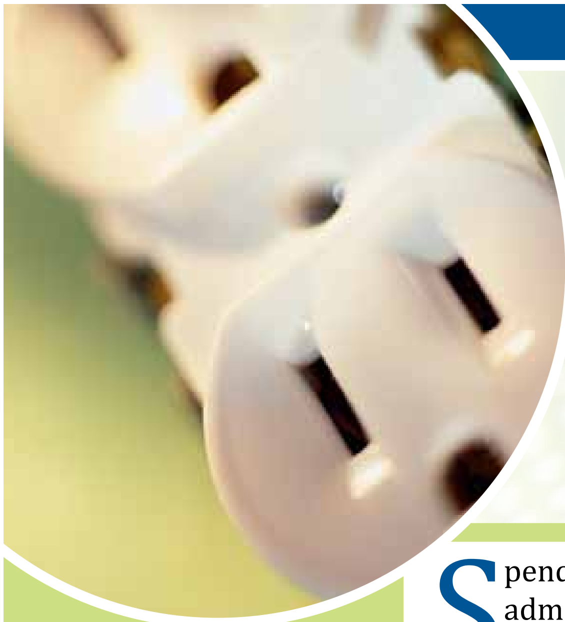
Attachment A



State Energy Efficiency Regulatory Frameworks

January 2010

Contents

Regulatory Framework Summary Table 2

Lost Revenue Recovery Mechanisms/Revenue Decoupling 5

Performance Incentives 11

Spending and budgets for utility-administered electric efficiency programs continue to grow, due in part to the evolution of state policies that allow utilities to pursue efficiency as a sustainable business. **This latest review by IEE staff summarizes ongoing and the most recent policies that promote program cost recovery, lost revenue recovery, and performance incentive mechanisms for electric utilities on a state-by-state basis.**

- The District of Columbia is the latest addition to a growing list of jurisdictions that have adopted revenue decoupling for the electric sector (state summary & map, p. 5). Idaho, Massachusetts, Minnesota, Oregon, Wisconsin and Vermont have also approved decoupling measures in the past two years. Delaware, Hawaii, Michigan, New Hampshire, New Jersey and New Mexico are considering some form of decoupling. Lost revenue adjustment mechanisms were recently approved in Ohio, Oklahoma, North Carolina, and South Carolina as part of larger cost recovery mechanisms. Utah also recently entered the discussion by passing a law that encourages utilities and the Commission to investigate decoupling mechanisms.
- Twenty one states currently have incentives in place, with another seven states pending (p. 11). Colorado, Hawaii, Kentucky, Michigan, Ohio, Oklahoma, North Carolina, Texas, South Carolina, Washington, and Wisconsin have approved new incentive mechanisms in the last two years; Idaho, Indiana, Kansas, Montana, New Mexico, North Carolina, New York, and Utah are each considering some form of performance incentive for efficiency.
- Duke Energy's "virtual power plant" model, which combines cost recovery, lost revenue recovery and incentives into an avoided cost charge, has recently been approved in North Carolina and a decision has been promised soon in South Carolina. The Ohio Commission approved the VPP program in 2008. Duke has proposed similar mechanisms in Indiana and Kentucky. ■

The Edison Foundation | Institute for Electric Efficiency

Advancing energy efficiency practices and demand response among electric utilities.

State Regulatory Framework Summary Table

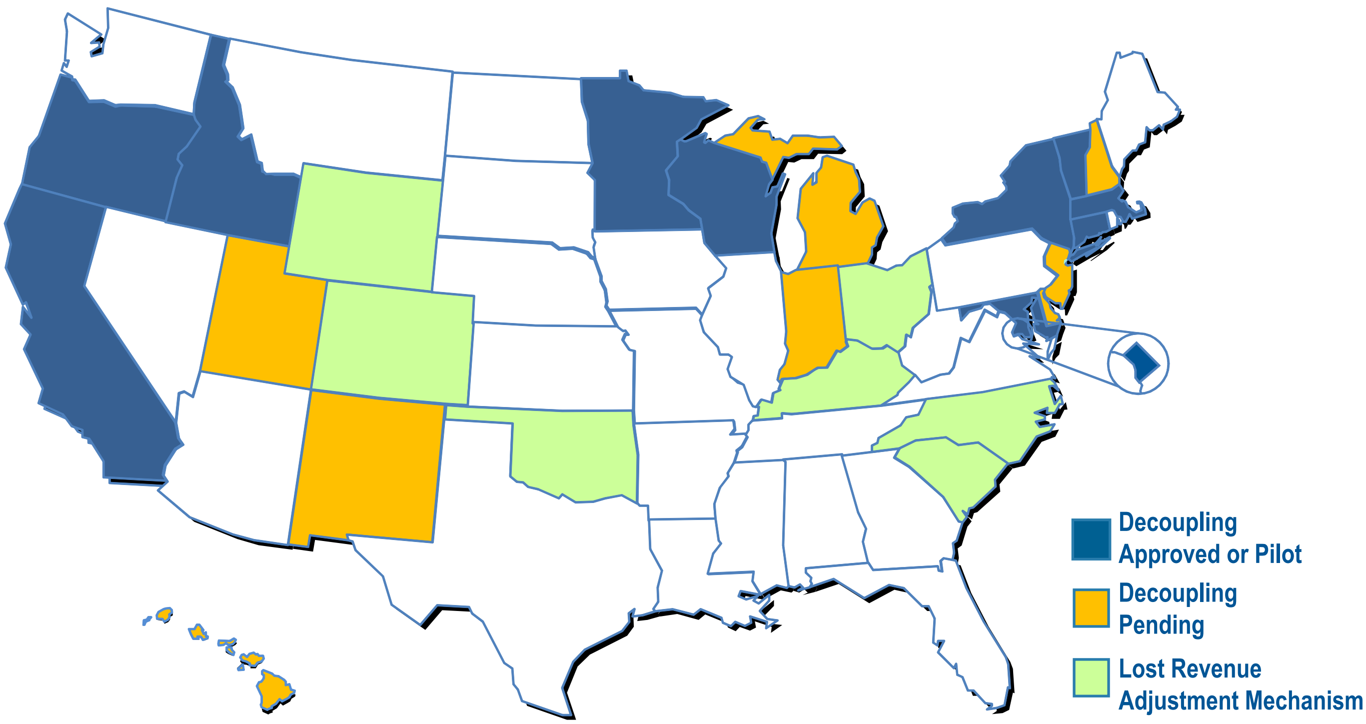
State	Direct Cost Recovery			Fixed Cost Recovery		Performance Incentives	Virtual Power Plant
	Rate Case	System Benefits Charge	Tariff Rider/ Surcharge	Decoupling	Lost Revenue Adjustment Mechanism		
Alabama	Yes						
Alaska							
Arizona		Yes	Yes			Yes	
Arkansas			Yes				
California	Yes	Yes		Yes		Yes	
Colorado	Yes		Yes		Yes	Yes	
Connecticut		Yes		Yes		Yes	
Delaware	Yes			Pending			
District of Columbia	Yes			Yes			
Florida			Yes				
Georgia	Yes					Yes (one program)	
Hawaii	Yes			Pending		Yes	
Idaho			Yes	Yes		Pending	
Illinois			Yes				
Indiana			Yes	Pending			Pending
Iowa	Yes		Yes				
Kansas	Yes					Pending	
Kentucky			Yes		Yes	Yes	Pending
Louisiana	Yes						
Maine		Yes					
Maryland			Yes	Yes			
Massachusetts		Yes		Yes		Yes	
Michigan			Yes	Pending		Yes	
Minnesota	Yes		Yes	Yes		Yes	
Mississippi	Yes						
Missouri	Yes						
Montana		Yes				Pending	
Nebraska							
Nevada	Yes					Yes	
New Hampshire		Yes		Pending		Yes	

State	Direct Cost Recovery			Fixed Cost Recovery		Performance Incentives	Virtual Power Plant
	Rate Case	System Benefits Charge	Tariff Rider/ Surcharge	Decoupling	Lost Revenue Adjustment Mechanism		
New Jersey		Yes		Pending			
New Mexico			Yes	Pending		Pending	
New York		Yes		Yes		Pending	
North Carolina			Yes		Yes	Yes	Yes
North Dakota							
Ohio			Yes		Yes		Yes
Oklahoma			Yes		Yes	Yes	
Oregon		Yes		Yes			
Pennsylvania	Yes		Yes				
Rhode Island		Yes				Yes	
South Carolina		Yes			Yes	Yes	Pending
South Dakota			Yes				
Tennessee							
Texas	Yes		Yes			Yes	
Utah	Yes		Yes	Pending	Pending	Pending	
Vermont		Yes		Yes		Yes	
Virginia							
Washington		Yes	Yes			Yes	
West Virginia							
Wisconsin	Yes		Yes	Yes		Yes	
Wyoming			Yes		Yes (MDU)		

Please note that although information in this document was compiled from primary sources, readers are encouraged to verify the most recent developments by contacting the appropriate commission or regulatory agency.

For inquiries, please contact Matthew McCaffree, Manager of Electric Efficiency, at mmccaffree@edisonfoundation.net. For further information, please visit http://www.edisonfoundation.net/IEE/.

Lost Revenue Adjustment & Revenue Decoupling Mechanisms for Electric Utilities by State



State	Description	Status	Codes, Orders & Resources
California	California has had some form of decoupling since 1982. The current "decoupling plus" program is a revenue decoupling program combined with performance incentives for meeting or exceeding energy efficiency targets (performance-based rates). Revenue requirements are adjusted for customer growth, productivity, weather, and inflation on an annual basis with rate cases every three or four years (varies by utility). The incentive structure caps penalties/earnings for energy efficiency programs at $450M.	Approved (Decoupling "Plus" approved in 2007)	Code Sec. 9 Section 739(3) and Sec. 10 Section 739.10 as amended by A.B. XI 29; Decisions 98-03-063 & 07-09-043
Colorado (LR)	A conditional portion of the performance incentive mechanism in Colorado (see p. 12) allows for Xcel to recover a $2M after-tax, "disincentive offset" payment for achieving greater than 80% of the annual energy savings goal.	Approved (2007)	HB-07-1037; Decision C08-560, Docket 07A-420E
Connecticut	As of 2007, all electric and gas utilities must include a decoupling proposal as a part of their individual rate cases. The type of decoupling is assigned on a utility-by-utility basis. United Illuminating uses a full decoupling mechanism, adjusted annually. Connecticut Light & Power will submit a proposal for a decoupling mechanism in their next rate case.	Approved (2007)	Public Act No. 07-242

State	Description	Status	Codes, Orders & Resources
Delaware	The Delaware Commission has recognized decoupling as a possible solution for promoting energy efficiency, but no plans have yet been approved for Delaware utilities. Delmarva Power will submit their decoupling plan in the next rate case in 2009.	Pending	Docket 59
District of Columbia	The DC Public Service Commission approved PEPCO's Bill Stabilization Adjustment (BSA) in October 2009. Like the BSA approved for Maryland, an RPC mechanism is employed which adjusts quarterly.	Approved (2009)	PSC Order 1053-E-549
Hawaii	An order was issued in October 2008 to investigate implementing a decoupling mechanism that could be structured much like that in California. Utilities are required to submit a 2009 test year rate case.	Pending	Docket 2008-0274
Idaho	A three year pilot for a fixed-cost adjustment (an RPC decoupling program) has been instituted and is currently employed by Idaho Power Company. Sales are adjusted for weather and rate increases are capped at 3% over the previous year. The mechanism is only applied to residential and small general service customers.	Approved - Pilot (2007)	PUC IPC-E-09-07, Order No. 30829
Indiana	The Utility Regulatory Commission recently approved Vectren's alternative regulatory plan, which included requests for performance incentives and lost revenue recovery. Vectren's decoupling proposal was rejected, but the commission did request that an alternative lost revenue proposal be submitted. Northern Indiana Power & Light and Indianapolis Power & Light have both proposed lost margin recovery mechanisms and both are pending before Commission.	Pending	Cause No. 43427
Kentucky (LR)	Lost revenue recovery mechanisms are determined on a case-by-case basis, but all electric utilities in Kentucky have DSM proposals in place that include similar lost revenue (LR) recovery due to DSM programs. For these utilities, LR is calculated using the marginal rate, net of variable costs, times the estimated kWh savings from a DSM measure over a three-year period.	Approved (2006)	Statute Ch. 278, Title 285; Docket 2007-00477; 2008-00473
Maryland	A plan to employ revenue decoupling for Maryland utilities under an RPC mechanism was approved in 2007, which adjusts quarterly. The mechanism is similar to the BSA approved for Washington, DC.	Approved (2007)	PSC Case No. 9093; Order 81518
Massachusetts	Gas and electric utilities in Massachusetts must include a decoupling proposal in their next rate case. Target revenues are determined on a utility-wide basis (full decoupling) and can be adjusted for inflation or capital spending requirements if necessary. The Massachusetts DPU expects that all utilities will have fully operational decoupling plans by 2012. In May 2009, National Grid was the first utility to submit a revenue decoupling ratemaking plan (RDR), which proposes an RPC mechanism that adjusts annually.	Approved (2008), full implementation by 2012	Docket 07-50; Docket 09-39

State	Description	Status	Codes, Orders & Resources
Michigan	Act 295 mandates that the Commission consider decoupling mechanisms proposed by the state's electric utilities. Consumers Energy and Detroit Edison have included decoupling proposals in the rate cases currently before the Commission. A decision in each case is expected in late 2009 or early 2010. Detroit Edison has proposed a revenue decoupling mechanism before the Commission. If approved, the proposed mechanism would normalize lost revenues for weather and have separate adjustments for each customer class.	Pending	Act 295; Case U-15768 and U-15751
Minnesota	A decoupling statute was passed in 2008 that allows for electric and gas utilities to implement decoupling pilot programs of no more than three years. Utilities are required to submit proposals to the state PUC for the structure of recovery mechanisms and frequency of true-ups (none submitted to date). Annual status reports are to be given to the state legislature once the programs are in place.	Approved - Pilot (2008)	Statute 216B.2412
New Hampshire	The New Hampshire PUC concluded in a January 2009 order that existing rate mechanisms are a barrier to energy efficiency. It has ordered that future rate mechanisms be tailored to individual utilities and be normalized for changes in weather, while not specifying the parameters of those mechanisms.	Pending	Order DE 07-064
New Jersey	Atlantic City Electric has proposed a RPC mechanism, or Bill Stabilization Agreement (BSA) as proposed, for their service territory. It is an RPC mechanism that calls for monthly true-ups with changes capped at 10% of previous fixed revenue amounts.	Pending	Docket Eo09010056
New Mexico	HB 305 was signed into law in 2008, requiring that all utilities "include all cost-effective energy efficiency and load management programs in their energy resource portfolios, that regulatory disincentives to public utility development of cost-effective energy efficiency and load management be removed [...]." As a result, the NM Public Regulation Commission is considering proposals for a lost revenue adjustment mechanism that would compensate the utilities based on lost margins through 2010, at which time the PRC may act to remove disincentives to EE through decoupling or other mechanisms (see the incentives summary for more information on the proposed incentive mechanism). A decision is pending.	Pending	HB305, Docket 08-00024-UT
New York	Following an April 2007 order, electric and gas utilities must file proposals for true-up based decoupling mechanisms in ongoing and new rate cases. Proposals have been approved for Consolidated Edison and Orange & Rockland utilities, both for revenue-per-class mechanisms. True-ups occur annually.	Approved (2007)	Cases 03-E-0640, 07-E-0949, & 07-E-0523

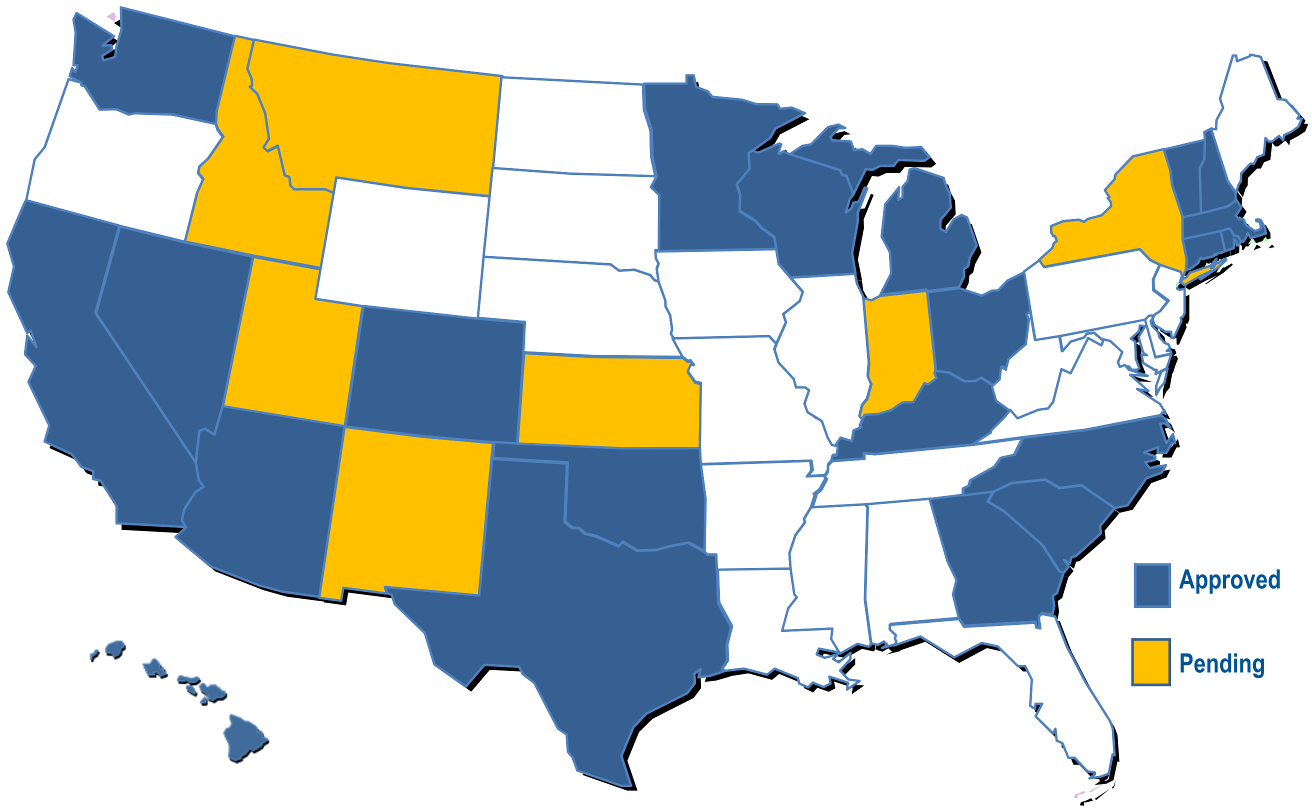
State	Description	Status	Codes, Orders & Resources
North Carolina (LR)	The Commission approved a proposed lost revenue adjustment mechanism for Progress Energy Carolinas as part of their cost recovery mechanism. Net lost revenues for each annual period are recovered over 3 years and determined by multiplying lost sales by a net lost revenue rate, which is the difference between the average retail rate applicable to the customer class impacted by the measure and (1) the related customer charge component of that rate, (2) the fuel component of the rate, and (3) the incremental variable O&M rate. True-ups occur annually. The Commission also approved a similar mechanism for Duke Energy Carolinas in December 2009 for energy efficiency measures only, coinciding with the approval of the utility's virtual power plant mechanism.	Approved (2009)	Docket E-2, Sub 931; Docket E-7, Sub 831
Ohio (LR)	As with Kentucky, lost revenue recovery mechanisms are determined on a case-by-case basis. Duke Energy Ohio recovers lost revenues resulting from their portfolio of EE programs through the DSM rider. LR is calculated as the amount of kWh sales lost due to the DSM programs times the energy charge for the applicable rate schedule, less variable costs, divided by the expected kilowatt-hour sales for the upcoming 12 month period. They are collected over a 36 month period. DP&L currently has a case pending. AEP Ohio chose not to seek LR in their prior rate case.	Approved (2007)	ORC §4928.143(B)(2)(h); 06-0091-EL-UNC
Oklahoma (LR)	OG&E has direct lost revenue adjustment ("Class Lost Revenue Factor") built in to the approved demand program rider (DPR) structure, which includes a shared savings mechanism (see p. 15). As the name implies, LR amounts are examined by customer class.	Approved (2009)	Cause No. PUD 200800059, Order 556179
Oregon	Portland General Electric was approved for a two year pilot employing an RPC decoupling mechanism. True-ups will occur annually.	Approved - Pilot (2009)	Order 09-020
South Carolina (LR)	The Commission approved a proposed lost revenue adjustment mechanism for Progress Energy Carolinas as part of their cost recovery mechanism. Net lost revenues for each annual period are recovered over 3 years and determined by multiplying lost sales by a net lost revenue rate, which is the difference between the average retail rate applicable to the customer class impacted by the measure and (1) the related customer charge component of that rate, (2) the fuel component of the rate, and (3) the incremental variable O&M rate. True-ups occur annually.	Approved (2009)	Docket 200-251-E
Utah	HJR 9 was passed into law (March 2009), which includes language supporting decoupling: "[T]he legislature expresses support for regulator mechanisms, which might include performance-based incentives, decoupling fixed cost recovery from sales volume, and other rate designs intended to help remove utility disincentives and create incentives to increase efficiency and conservation... ."	Pending - Law passed, mechanisms yet to be proposed	HJR009

State	Description	Status	Codes, Orders & Resources
Vermont	An RPC decoupling program was approved for Green Mountain Power under the Alternative Regulation Plan. Rates can be adjusted up to four times per year with an annual reconciliation on allowed earnings. Changes in base rates cannot exceed ~2% per year. CVPS was also approved for decoupling in 2008.	Approved (2007)	Dockets 7175, 7176 & 7336
Wisconsin	Decoupling was approved for WPSC in December 2008 (specified as a "Revenue Stabilization Mechanism"), allowing the utility to pursue a four-year pilot program. WPSC is required to pursue three community-based pilots, which will be regularly reviewed (at 2, 12, 24, and 30 months). True-ups occur annually and over- or under-collection is capped at approximately $14 million. WPL will submit a similar proposal for implementation in 2010.	Approved - Pilot (2008)	Dockets 6680-UR-116 (WPL) & 6690-UR-119 (WPSC)
Wyoming (LR)	A tracking adjustment mechanism that includes direct lost revenue recovery was approved for a small service territory covered by Montana Dakota Utilities. The adjustment applies to all MDU customers to recover costs and lost revenues for load management programs only.	Approved (2007)	Docket No. 20004-65-ET-06

The table of lost revenue recovery mechanims for electric utilities was prepared by the Institute for Electric Efficiency using the latest public data available as of January 11th, 2010. Readers are encouraged to verify the most recent developments in decoupling by contacting the appropriate state regulator or commissioner's office.

For inquiries, please contact Matthew McCaffree, Manager of Electric Efficiency, at mmccaffree@edisonfoundation.net. For further information, please visit http://www.edisonfoundation.net/IEE/.

Performance Incentives for Electric Efficiency by State



State	Performance Incentive Description	Status	Relevant Statute, Code or Order
Arizona	Arizona Public Service (APS) has performance incentives in place under a shared savings mechanism, set at 10% of DSM program net economic benefits and capped at 10% of total DSM expenditures. An APS proposal to modify the incentive mechanism in 2008 requesting recovery of net lost revenues as well as removal of the cap on the incentive was denied.	Approved (2005)	Decision 67744, Docket E-01345A-05-0816, et al
California	California utilities earn an incentive on energy efficiency programs under a shared savings mechanism called an energy efficiency risk-reward incentive mechanism. Revenue from eligible energy efficiency programs is the product of the Earnings Rate (ER) and net benefits. The ER is 12% if the utility achievement towards CPUC goals is greater than 100%, 9% if the goal achievement is between 85 and 100% and 0% if the goal achievement is between 65 and 85%; if the achievement of goals is less than 65%, the utility pays a penalty. Net benefits are calculated as two-thirds of the TRC Net Benefit and one-third of the PAC Net Benefit. In January 2009, the CPUC instituted a rule making (09-01-019) to examine and reform the EE incentive mechanism.	Approved (2007)	R.06-04-010; 09-01-019

State	Performance Incentive Description	Status	Relevant Statute, Code or Order
Colorado	HB 07-1037 (C.R.S. §40-3.2-104) requires investor-owned electric utilities to achieve at least 5% percent reduction of retail energy sales and capacity savings by 2018, based on 2006 sales. The law further states that the Commission shall allow electric DSM investments an opportunity to be more profitable to the utility than any other utility investment that is not already subject to an incentive. The Commission approved the following incentive package to Public Service Colorado: - A "disincentive offset" of $2m/year (after tax) for each year approved DSM plan implemented to offset lost margins; if < 80% of yearly energy goal achieved, the offset may be reduced. - Performance incentives for surpassing "modest" goals; for each 1% of goal reached beyond 80%, company to earn additional 0.2% of net economic benefits, up to 10% at 130% of goal attainment, up to 12% at 150% of goal attainment. Incentives adjusted for 2009 to reflect least-cost planning commitments. - Incentives are allowed via annually trued up DSM Cost Adjustment and are capped at 20% of total annual DSM expenditures.	Approved (2007)	HB-07-1037; Decision C08-560, Docket 07A-420E
Connecticut	The CT PUC requires annual hearings for utilities, where the past year's results for energy savings are reviewed and a performance incentive is determined, which ranges from 1% to 8% of program costs. The minimum threshold of 70% of goals earns the minimum (1%) incentive. Reaching 100% of goals earns 5%, and for reaching 130% of goals earns 8%.	Approved (first in 1988, mechanism changes over time)	Docket 07-10-03
Georgia	Although utilities in Georgia may recover costs and an additional sum for Commission-approved DSM programs, only the Power Credit Single Family Program (Georgia Power) is currently active. The utility may earn an additional sum of 15% of the NPV of the net benefits of the program, contingent on the program achieving at least 50% of projected participation levels.	Approved - Single program only (2007)	Case 24505-U
Hawaii	As part of the state's transition plan to establish a third-party administrator for efficiency programs, the HECO companies are responsible for administering their own DSM programs until the transition date. HECO may earn a shared percentage of savings of 1%-5% with an incentive cap of $2M.	Approved (2008)	Docket & Order 23258, Docket 2007-0323

State	Performance Incentive Description	Status	Relevant Statute, Code or Order
Idaho	Idaho Power (IPC) was approved for a three-year pilot beginning in January 2007 and ending in December 2009. Under the pilot, the Company receives an incentive payment if the market share of homes constructed under the ENERGY STAR Homes Northwest program exceeds a target percentage of new homes constructed. IPC earns an incentive if the program exceeds the market share goal (7% in 2007, 9.8% in 2008, 11.7% in 2009). Incentives are capped at 10% of program net benefits. Penalties are levied if IPC does not meet a minimum market share percentage. On May 14, 2009, it was ordered that Idaho Power neither earn an incentive nor incur a penalty for the ENERGY STAR related program and that the pilot program be discontinued retroactively as of January 1, 2009.	Approved - Pilot (2007); Discontinued (Jan. 1, 2009)	IPC-E-06-32, Order 30268; IPC-E-09-04
Indiana	The state statute allows for either shared savings or adjusted/ bonus ROE mechanisms as DSM incentives. Duke Energy has submitted a proposal for an avoided cost recovery charge for EE programs. Vectren Energy Indiana, Northern Indiana Public Service Company (NIPSCO), and Indianapolis Power and Light have also filed DSM plans requesting performance incentives. All cases are currently pending.	Pending	Administrative Code, Title 170, Art. 4; Cause No. 43374; Cause No. 43427; Cause No. 43618; Cause 43623
Kansas	The State Corporation Commission found that it has "broad authority to provide incentives for energy efficiency" in 2007, but did not specify a mechanism in that order. Kansas Statute 66-117 allows a return of 0.5% to 2% on energy efficiency investments above the allowed rate of return. No plans have yet been approved for any utilities.	Pending; law in place, no programs approved	Docket 08-GIMX-441-GIV; Statute 66-117
Kentucky	State law allows for shareholder incentives through the DSM statute, specifically "incentives designed to provide positive financial rewards to a utility to encourage implementation of cost-effective demand-side management programs." Incentive mechanisms are approved on a case-by-case basis and both Duke Energy and Kentucky Power (AEP) have a shared savings mechanism in place where they receive an incentive of up to 10% of program costs for exceeding goals.	Approved (2007)	Rev. Stat. 278.285(1)(c); Docket 2008-00473; 2007-00477
Massachusetts	The incentive allows utilities to earn about 5% of program costs for energy efficiency programs that meet established program goals. The incentive structure is determined on a program-by-program basis but generally utilizes a three-tiered structure. The first "design performance" level is defined as performance that a Program Administrator expects to achieve in implementing its energy efficiency programs. The second "threshold performance" level is 75% of the design level. The third "exemplary performance" level is 125% of the design level. Incentives are awarded only if a program achieves the threshold level or above.	Approved (2000)	Docket 04-11; Order 98-100

State	Performance Incentive Description	Status	Relevant Statute, Code or Order
Michigan	The Commission approved DTE's energy optimization plan in 2009, which includes an incentive mechanism that allows the utility to earn up to 15% of program spending (a cap mandated by PA 295) if they reach 125% of their savings goals. An incentive payment is applied only if DTE exceeds its savings goal. PA 295 contains two provisions authorizing utilities to receive an economic incentive for energy efficiency programs. To be eligible, utilities must request that appropriate energy efficiency program costs be capitalized and earn a normal rate of return. Utilities can request a performance incentive mechanism to provide additional earnings to shareholders if they exceed the annual energy savings target. Incentives are capped at 15% of the total program cost.	Approved (2009)	PA 295 (2008); U-15806
Minnesota	The PUC revised the performance incentive originally approved in 1999. Under the new agreement, utilities retain a portion of net benefits based on the level of achievement, measured as a percent of retail sales. The award scale for this modified shared savings mechanism is calibrated to award $0.09/kWh at 1.5% of sales (e.g. if a utility achieves savings equal to 1.5% of sales, it will receive $0.09 for every kWh saved. A final order is pending.	Approved (1999); Revised mechanism (2009)	Docket CI-08-133, Statute 216B.241
Montana	MT statute allows for the Public Service Commission to add 2% to the authorized rate of return for DSM investments. It has not yet been approved for a specific utility.	Passed into law, but not implemented by utility	Code 69-3-712
Nevada	Nevada revised its regulations for IRP and DSM in 2004 to allow utilities to earn as much as 500 basis points above allowed return-on-equity (ROE) for applicable, approved DSM costs (+5%). Utilities must follow approved plans and budgets to earn the incentive amount. The order calls for applying the utility's debt-to-equity ratio to the fraction of capitalized DSM costs, and then applying the extra 5% ROE to that amount.	Approved (2004)	Docket No. 02-5030
New Hampshire	There are two separate incentives in NH. The cost-effectiveness incentive is awarded for programs that achieve a cost effectiveness ratio of 1.0 or higher. The incentive is calculated as 4% of the planned EE budget times the ratio of actual to planned cost effectiveness. The energy savings incentive is awarded when actual lifetime kWh savings are greater than or equal to 65% of projected savings. The incentive is 4% of the planned EE budget times the ratio of actual to planned energy savings. Target incentive amounts are calculated separately for residential and commercial/industrial sectors and are capped at 12% of the planned sector budgets.	Approved (2000)	Order 23.574

State	Performance Incentive Description	Status	Relevant Statute, Code or Order
New Mexico	A proposed rule making is currently before the PSC that, if approved, would allow utilities to receive an incentive for EE based on energy saved and to receive compensation for revenue lost due to efficiency programs. Additionally, HB 305 was passed in 2008 which requires all utilities to "include all cost-effective energy efficiency and load management programs in the energy resource portfolios."	Pending	Case 08-00024-UT; NM HB 305
New York	New York has recently allowed for performance incentives to be included in utility rate cases and the Commission is in the process of reviewing energy efficiency plans of several NY utilities. The order caps the aggregate incentives at $40M per year statewide and target megawatt-hours will be set for each year at the time of review for the EE plans.	Pending	Case 07-M-0548
North Carolina	North Carolina state law states that a utility may propose incentives for demand side management or energy efficiency programs to the Commission for consideration. The commission approved Progress Energy Carolina's incentive mechanism that allows for an incentive of 8% of NPV of benefits from DSM programs and 13% of NPV from EE programs. The Commission is considering an avoided cost recovery mechanism submitted by Duke Energy. The Commission issued a notice of decision approving Duke Energy Carolinas' Save-a-Watt program in December 2009 with a full decision to follow in January 2010. The program is similar to that in Ohio, where Duke will receive 50% of the net present value (NPV) of the avoided costs for conservation and 75% of the NPV for demand response.	Approved - Progress Energy Carolinas (2009), Duke Energy (2009)	Docket E-2, sub 931; Docket E-7, Sub 831
Ohio	Duke Energy received approval in December of 2008 for its proposed "Save-a-Watt" program, where the utility will receive 50% of the NPV of the avoided costs for energy conservation and 75% of the NPV of the avoided costs for demand response. Demand response programs are viewed by the parties as having a useful life of 1 year, while energy conservation programs have useful lives of up to 15 years.	Approved (2008)	Docket 08-920-EL-SSO
Oklahoma	A shared savings program has been approved for Public Service Oklahoma (AEP) which allows for two different returns: an incentive of 25% of net savings for programs for which savings can be estimated and 15% of the costs for other programs (e.g. education and marketing programs). OG&E also has an incentive mechanism where they receive shared benefits for achieving savings goals, calculated on a measure-by-measure basis. The utility may earn up to 25% for each measure where the TRC > 1.0 and up to 15% for each measure where the TRC < 1.0.	Approved - PSO (2008), OG&E (2009)	Cause No. PUD 200700449, Order 555302; Cause No. PUD 200800059, Order 556179

State	Performance Incentive Description	Status	Relevant Statute, Code or Order
Rhode Island	The shareholder incentive mechanism includes two components: performance-based metrics for specific program achievements, and kWh savings targets by sector. The program performance metrics are established for each individual program, such as achieving specific savings or a certain market share for the targeted energy-efficient technology. If Narragansett (d/b/a National Grid) achieves the savings goal, it receives 4.4% of the eligible budget. The threshold performance level is 60% of the savings goal. Once the threshold level has been reached, the utility has the ability to earn an additional incentive per kWh saved up to 125% of target savings. Incentive rates change by customer class.	Approved (2005)	Docket 3635, Order 18152
South Carolina	South Carolina law stipulates that the PSC "may adopt procedures that encourage electrical utilities [...] to invest in cost-effective energy efficient technologies and energy conservation programs." The commission approved Progress Energy Carolina's incentive mechanism that allows for an incentive of 8% of NPV of benefits from DSM programs and 13% of NPV from EE programs. Duke Energy's original avoided cost mechanism was rejected, but the Commission invited re-submission. Duke's EE programs that were proposed separately were approved as of June 1, 2009 with all costs deferred. A modified save-a-watt regulatory model was filed in the summer of 2009. A ruling is expected in early 2010.	Approved for Progress Energy Carolinas (2009); Pending for Duke Energy	Title 58. Public Utilities, Services And Carriers, Chapter 37. Energy Supply And Efficiency; Dockets 2008-251-E (Progress Energy), 2007-358-E, & 2008-251-E (Duke Energy)
Texas	Texas state code specifies that a utility may be awarded a performance bonus (a share of the net benefits) for exceeding established demand reduction goals that do not exceed specified cost limits. Net benefits are the total avoided cost of the eligible programs administered by the utility minus program costs. The performance bonus is based on the utility's energy efficiency achievements for the previous calendar year. If a utility exceeds 100% of its demand reduction goal, the bonus is equal to 1% of the net benefits for every 2% that the demand reduction goal has been exceeded, up to a maximum of 20% of the utility's program costs. A utility that meets at least 120% of its demand reduction goal with at least 10% of its savings achieved through Hard-to-Reach programs receives an additional bonus of 10% of the bonus calculated.	Approved (2008)	PUC of Texas Substantial Rule §25.181(h); CenterPoint Energy Houston Electric 2008 Energy Plan & Report, Project No. 35440
Utah	HJR 9 was approved in March 2009 and includes language supporting incentives: "[T]he legislature expresses support for regulator mechanisms, which might include performance-based incentives, decoupling fixed cost recovery from sales volume, and other rate designs intended to help remove utility disincentives and create incentives to increase efficiency and conservation... ."	Pending - Law passed but no mechanisms proposed	UT HJR009

State	Performance Incentive Description	Status	Relevant Statute, Code or Order
Vermont	The operator of Efficiency Vermont, VEIC, is eligible to receive a performance incentive for meeting or exceeding specific goals established in its contracts. There is also a holdback in the compensation received by VEIC, pending confirmation that contractual goals for savings and other performance indicators have been achieved. The initial contract (2000-2002) allowed incentives of up to 2% of the overall energy efficiency budget over the three-year contract period. Incentives increased to 3.5% of the EE budget for the 2006-2008 period.	Approved (2000)	Contract 0337956, Attachment C
Washington	The Commission approved a shared savings ("Net Shared Incentive") mechanism for Puget Sound Energy in 2006 that either rewards or penalizes PSE for exceeding or not meeting savings targets, respectively. The savings target for 2009 is 278,000 MWh, with a maximum incentive/penalty of +/- 50% and a "dead band" if the utility saves between 90-99.9% of the target. In addition to meeting the overall savings goal, PSE must meet at least 75% of the projected savings targets in both the residential and commercial/industrial sectors. 75% of the full incentive amount will be collected in the year after program implementation, with the remaining amount collected the following year.	Approved (2006)	Docket UE-060266
Wisconsin	As of 2008, Wisconsin Power & Light (Alliant Energy) may earn the same rate-of-return on its investments in energy efficiency made through its "shared savings" program for commercial and industrial customers as it earns on other capital investments. Utilities may propose incentives as part of their rate cases, but there have been no proposals from other utilities under the most recent version of performance incentives. [Note: Wisconsin dropped performance incentives in the 1990s.]	Approved (2008)	Docket 6680-UR-114

Summary of Incentive Mechanisms

Approach	State
Earn a percentage of program costs for achieving savings target	CO, CT, KY, MA, MI, MN, NH, RI, TX, VT, WA
Earn a share of achieved savings	AZ, CA, GA, HI, OK
Earn a percentage of the NPV of avoided costs	NC, OH, SC
Altered rate of return for achieving savings targets	NV, WI

Note: Information on electric efficiency performance incentives was compiled using the latest public data available as of January 11th, 2010. Readers are encouraged to verify the most recent developments by contacting the appropriate commission or regulatory agency. Other resources used in the preparation of this report were ACEEE's State Energy Efficiency Program Database, documents from EPA's National Action Plan on Energy Efficiency, and resources from the Regulatory Assistance Project.

For inquiries, please contact Matthew McCaffree at mmccaffree@edisonfoundation.net.
For further information, please visit http://www.edisonfoundation.net/IEE/.

For more information contact:

Institute for Electric Efficiency
701 Pennsylvania Ave, NW
Washington, DC 20004
202.508.5440 • 202.508.5035
info@edisonfoundation.net
www.edisonfoundation.net/IEE