Robin Carnahan
Secretary of State

Administrative Rules Division
Rulemaking Transmittal Receipt

Rule ID: 12652
Date Printed: 3/14/2011
Rule Number: 4 CSR 240-20.094
Rulemaking Type: Final Order Rule
Date Submitted to Administrative Rules Division: 3/14/2011
Date Submitted to Joint Committee on Administrative Rules: 2/9/2011

Name of Person to Contact with questions concerning this rule:

Content: Harold Stearley	Phone: 2-8459	Email: harold.stearley@psc.mo.gov	Fax:
RuleDataEntry:	Phone:	Email:	Fax:

Included with Rulemaking:

Cover Letter 3/14/2011

Print Close

Robin Carnahan
Secretary of State
Administrative Rules Division

RULE TRANSMITTAL

Administrative Rules Stamp

RECEIVED
MAR 14 2011
SECRETARY OF STATE
ADMINISTRATIVE RULES

Rule Number 4 CSR 240-20.094

COPY

Use a "SEPARATE" rule transmittal sheet for EACH individual rulemaking.

Name of person to call with questions about this rule:
Content Harold Stearley Phone 573-522-8459 FAX
Email address harold.stearley@psc.mo.gov

Data Entry same Phone FAX
Email address

Interagency mailing address Public Service Commission, 9th Fl, Gov.Ofc Bldg, JC, MO

TYPE OF RULEMAKING ACTION TO BE TAKEN

☐ Emergency rulemaking, include effective date

☐ Proposed Rulemaking

☐ Withdrawal ☐ Rule Action Notice ☐ In Addition ☐ Rule Under Consideration

☒ Order of Rulemaking

Effective Date for the Order

☒ Statutory 30 days OR Specific date

Does the Order of Rulemaking contain changes to the rule text? ☐ NO

☒ YES—LIST THE SECTIONS WITH CHANGES, including any deleted rule text:
Changes have been made to sections (1)(C), (1)(D), (1)(L), (1)(M), (1)(N), (1)U), (1)(W), (1)(X), (1)(Y), (2), (3), (4), (6)(H), (8)(A), and (8)(B).
Sections (1)(T), (1)(V), and (1)(Z) have been relettered.
Section (1)(S) has been added.

Small Business Regulatory Fairness Board (DED) Stamp

JCAR Stamp

JOINT COMMITTEE ON
FEB 09 2011
ADMINISTRATIVE RULES

Commissioners
ROBERT M. CLAYTON III
Chairman
JEFF DAVIS
TERRY M. JARRETT
KEVIN GUNN
ROBERT S. KENNEY

Missouri Public Service Commission

POST OFFICE BOX 360
JEFFERSON CITY MISSOURI 65102
573-751-3234
573-751-1847 (Fax Number)
http://www.psc.mo.gov

WESS A. HENDERSON
Executive Director
VACANT
Director, Administration and Regulatory Policy
ROBERT SCHALLENBERG
Director, Utility Services
NATELLE DIETRICH
Director, Utility Operations
STEVEN C. REED
Secretary/General Counsel
KEVIN A. THOMPSON
Chief Staff Counsel

Honorable Robin Carnahan
Secretary of State
Administrative Rules Division
600 West Main Street
Jefferson City, Missouri 65101

Dear Secretary Carnahan:

Re: 4 CSR 240-20.094 Demand-Side Programs

CERTIFICATION OF ADMINISTRATIVE RULE

I do hereby certify that the attached is an accurate and complete copy of the order of rulemaking lawfully submitted by the Missouri Public Service Commission for filing.

Statutory Authority: Sections 393.1075, RSMo Supp. 2009, and 386.040 and 386.250, RSMo 2000.

If there are any questions, please contact:

Harold Stearley, Senior Regulatory Law Judge
Missouri Public Service Commission
200 Madison Street
P.O. Box 360
Jefferson City, MO 65102
(573) 522-8459
Harold.stearley@psc.mo.gov

Morris L. Woodruff

Morris Woodruff
Chief Regulatory Law Judge

Title 4 – DEPARTMENT OF ECONOMIC DEVELOPMENT
Division 240 – Public Service Commission
Chapter 20—Electric Utilities

ORDER OF RULEMAKING

By the authority vested in the Public Service Commission under sections 393.1075, RSMo Supp. 2009, and 386.040 and 386.250, RSMo 2000, the commission adopts a rule as follows:

4 CSR 240-20.094 is adopted.

A notice of proposed rulemaking containing the text of the proposed rule was published in the *Missouri Register* on November 15, 2010 (35 MoReg 1667). Those sections with changes are reprinted here. This proposed rule becomes effective thirty (30) days after publication in the *Code of State Regulations.*

SUMMARY OF COMMENTS: A public hearing on this proposed rule was held December 20, 2010, and the public comment period ended December 15, 2010. The commission received a number of written comments from seventeen entities, many of which were duplicated or echoed from the various entities and involve the same sections or subsections of the proposed rule. Consequently, these comments have been consolidated into 18 central comments, which are addressed below. At the public hearing, seventeen (17) witnesses testified. The entities filing comments were: AARP, Union Electric d/b/a Ameren Missouri ("Ameren Missouri"), the Consumers Council of Missouri ("CCM"), The Empire District Electric Company ("Empire"), KCPL Greater Missouri Operations Company ("GMO"), Great Rivers Environmental Law Center ("GRELC"), Kansas City Power and Light Company ("KCPL"), the Missouri Department of Natural Resources ("MDNR"), the Missouri Energy Development Association ("MEDA"),[1] the Missouri Energy Group ("MEG"), the Missouri Industrial Energy Consumers ("MIEC"),[2] the National Resources Defense Council ("NRDC"), the Office of the Public Counsel ("OPC"), OPOWER, Inc. ("OPOWER"), Renew Missouri, the Staff of the Missouri Public Service Commission ("Staff"), the Sierra Club, Walmart Stores East, LP, and Sam's East.

All of the comments were generally in support of a rule to implement Demand-Side Programs and Demand-Side Programs Investment Mechanisms ("DSIMs"), but many had suggestions for specific changes to the proposed rule and raised concerns regarding the timing of authorizing DSIMs and whether those mechanisms could include recovery of lost revenues. It should be noted that this proposed rule operates in conjunction with proposed rules 4 CSR 240-3.163; 4 CSR 240-3.164; and 4 CSR 240-20.093. All of these rules were promulgated to implement Section 393.1075, RSMO, the Missouri Energy Efficiency Investment Act ("MEEIA"). Any comments directed towards 4 CSR 240-20.094 may be interrelated with these other proposed rules and the interplay between these proposed rules may need to be addressed in the context

---

[1] The MEDA members include: KCPL, GMO, Empire and Ameren Missouri.

[2] MIEC members include: Anheuser-Busch Companies, Inc., BioKyowa, Inc., The Boeing Company, Doe Run, Enbridge, Ford Motor Company, General Motors Corporation, GKN Aerospace, Hussmann Corporation, JW Aluminum, MEMC Electronic Materials, Monsanto, Procter & Gamble Company, Nestlé Purina PetCare, Noranda Aluminum, Saint Gobain, Solutia and U.S. Silica Company.

of this order or rulemaking; however, in and of itself, this rule specifically addresses Demand-Side Programs. It should also be noted that while comments were directed at specific sections and subsections of the rule, due to changes in the proposed rule those number citations may not match the final numbering of the sections and subsections of the rule.

COMMENT # 1 - General Changes in Relation to Alleged Single-Issue Ratemaking:

AARP, CCM, the MIEC, OPC, and Staff all believe that any section or subsection of this rule that allows a rate adjustment outside of a general rate case would constitute unlawful single-issue ratemaking. AARP, CCM and OPC state it is their belief that the legislature purposely deleted any language in SB 376 (the legislation ultimately codified as Section 393.1075, RSMo) that would have allowed for changes to a demand-side program investment mechanism in between general rate cases. The sections and subsection of this rule identified by these entities that would require change based upon this comment are: 4 CSR 240-20.094(1)(J); (1)(L); (1)(M); (1)(N); (1)(Y); (3)(E).

MEDA, MDNR, NRDC, Sierra Club, Renew Missouri, GRELC on the other hand, believe that the language in Section 393.1075.3 and 5 mandating the commission to provide timely cost recovery and timely earnings opportunities by developing cost recovery mechanisms without limitation allows the commission to establish and approve demand-side programs outside the framework of a general rate case. Section 393.1075.11 states the commission "may adopt rules and procedures . . . as necessary, to ensure that electric corporations can achieve the goals of this section." Additionally, these entities point out that Section 393.1075.13 requires the use of a separate line item for charges attributable to demand-side programs, which is consistent with other billing elements that are adjusted outside of a general rate case. Taxes, fuel adjustment clauses, purchased gas adjustments and infrastructure system replacement surcharges are all billed in this fashion. While language in original version of SB 376 providing for a "cost adjustment clause" was removed, the legislature added "timely cost recovery" broadening the commission's discretion with developing cost recovery mechanisms.

Response: The commission believes that the express language in Section 393.1075, RSMo unequivocally requires the commission provide timely cost recovery for utilities when effectuating the declared social policy of valuing demand-side investments equal to traditional investments in supply and delivery infrastructure. MEEIA contemplates non-traditional investments and mandates timely cost recovery. The language of the proposed rule does not establish any specific type of demand-side investment mechanism ("DSIM"). Instead the proposed rule allows the maximum latitude for creating Demand-Side Programs and the associated DSIMs while allowing for periodic adjustments in conformity with the language in the statute. The argument that the proposed rule would in and of itself authorize single-issue ratemaking is unfounded and premature. Until an exact DSIM is established there is no way to claim that original implementation or any periodic adjustments would constitute single-issue ratemaking.

Additionally, the statutory language from which the prohibition against single-issue ratemaking is derived originates in Section 393.270.4. That subsection reads, in pertinent part: "In determining the price to be charged for . . ., electricity . . . the commission *may consider all facts which in its judgment have any bearing upon a proper determination* of the question . . ." The statute is permissive. It allows the commission the discretion to examine all facts that the commission believes are relevant. There is no set statutory requirement for how many or what type of facts or factors the commission must consider when making its determination. Indeed, the legislature has delegated its authority to the commission, being the expert agency charged with making these determinations, to decide what factors must be examined when determining the price to be charged for electricity. The commission will make no changes to the language identified by these comments in the proposed rule or to any other language in the rule that would be related to the issue raised in these comments.

COMMENT # 2 - LOST REVENUE RECOVERY:

AARP, CCM, OPC, MIEC and Staff believe that the lost revenue recovery mechanism provisions of the draft rules are unlawful because those provisions are not authorized by statute. These entities believe that lost revenue does not fit in a cost category. The sections and subsection of this rule identified by these entities that would require change based upon this comment are: 4 CSR 240-20.094(1)(J); (1)(N); (1)(R); (1)(T); and (4).

MDNR, NRDC, Sierra Club, Renew Missouri, GRELC comment that lost revenue recovery is not cost recovery or an earnings opportunity. These entities believe that under the mechanism for recovering lost revenues in the proposed rule, utilities would continue to see higher levels of revenue recovery with higher sales. Therefore, they believe the utility will find itself facing the same conflict it currently faces at the prospect of taking actions or supporting policies to save energy and thereby save their customers money, knowing that such actions would cause their shareholders to miss out on the earnings from higher sales. These entities refer to the incentive to maintain higher sales as the "throughput incentive." And believe this is a strong disincentive for utilities to invest in energy efficiency or to support energy saving policies and measures outside their control.

MEG, objects to any language that would allow a lost revenue recovery mechanism, not because it is unlawful, but because it believes that reduced costs associated with reduced sales will balance out. MEG also believes that a lost recovery mechanism is inconsistent with the way other charges are handled. According to MEG, a utility believes that energy efficiency programs will reduce sales and reduce contributions to fixed costs, but using that same reasoning, every time the utility adds a customer it increases sales and contributions to fixed costs. Consequently, MEG concludes, there should be a refund to customers in any class of ratepayers every time a customer is added. MEG also believes there is no way to determine the actual effect of the various energy efficiency programs.

In addition to the other comments made, Staff states that only eight other states allow recovery of lost revenues. According to Staff other states that have had such a recovery mechanism in the past have abandoned it. Staff claims that the movement away from direct reimbursement for lost revenues is likely due to several factors including: the fact that the approach is vulnerable to "gaming" by over-claiming savings; that it typically leads to very contentious reconciliation hearings as parties argue about the measurement of savings; and that it doesn't do anything to address the utility disincentive regarding broader energy efficiency policies beyond the specific program addressed with the mechanisms. Staff notes that other commissions have addressed this issue either through decoupling mechanisms and/or performance incentives." Staff recommends the "throughput incentive" be addressed through the utility incentive component of a DSIM.

MEDA believes that 393.1075.3 mandates recovery of all reasonable and prudent costs and requires the commission to ensure that utility financial incentives are aligned with helping customers use energy more efficiently and in a manner that sustains or enhances utility customers' incentives to use energy more efficiency. MEDA members comment that unless a utility's lost revenues are included in the DSIM or other recovery mechanism, there will always be a financial bias against fully utilizing demand-side management programs that result in the reduction of a utility's revenues.

RESPONSE: Section 393.1075.3 requires the commission to "allow recovery of *all* reasonable and prudent costs of delivering cost-effective demand-side programs." Additionally, Section 393,1075.3(2) requires the commission to ensure that "utility financial incentives are aligned with helping customers use energy more efficiently and in a manner that sustains or enhances utility customers' incentives to use energy more efficiently." Section 393.1075.5 states the commission "may develop cost recovery mechanisms to further encourage investment in demand-side programs . . ." Lost revenue is a cost of delivering cost-effective demand-side programs, and the proposed rule, in conjunction with the interrelated proposed rules, i.e. 4 CSR 240-3.163, 4 CSR 240-3.164; and 4 CSR 240-20.093, require evaluation, measurement and verification (EM&V"). Any request for recovery of lost revenue will have to be verified and approved by the commission prior to recovery.

At the rulemaking hearing on December 20, 2010, several participants commented that decoupling could prevent over and under-earning and that it might present a better long-term solution than allowing recovery of lost revenues. However, Section 393.1075.5 requires the commission to conclude a docket studying any rate design modification to those currently approved by the commission prior to promulgating an appropriate rule in that regard. Decoupling represents such a change in rate design and no docket has been opened at this time to fully explore this or other possible changes. The commission has been directed by the legislature to implement Section 393.1075, and while this proposed rule may ultimately be an intermediary step to decoupling or other changes in rate design models, promulgating a lost revenue recovery mechanism is authorized by MEEIA and with verification methods in place the potential for possible "gaming of the system" is minimized. The commission will make no changes to the language identified by these comments in the proposed rule or to any other language in the rule that would be related to the issue raised in these comments.

COMMENT # 3 – DEFINITION OF LOST REVENUE:

A number of participants raised an issue concerning the issue of how the proposed rule defines lost revenue. Thus, should the commission include provisions for recovery of lost revenues, these entities debate how "lost revenues" should be defined.

Proposed Rule 4 CSR 240-20.094(1)(T) defines lost revenue as:

Lost revenue means the net reduction in utility retail revenue, taking into account all changes in costs and all changes in any revenues relevant to the Missouri jurisdictional revenue requirement, that occurs when utility demand-side programs approved by the commission in accordance with 4 CSR 240-20.094 cause a drop in net retail kWh delivered to jurisdictional customers below the level used to set the electricity rates. Lost revenues are only those net revenues lost due to energy and demand savings from utility demand-side programs approved by the commission in accordance with 4 CSR 240- 20.094 Demand-Side Programs and measured and verified through EM&V.

Proposed Rule 4 CSR 240-20.094(1)(N) defines DSIM utility lost revenue as:

DSIM utility lost revenue requirement means the component of the utility's revenue requirement explicitly approved (if any) by the commission in a utility's filing for demand-side program approval proceeding to address the recovery of lost revenue;

MEDA believes that if the commission is going to allow recovery of lost revenue, the definition of "lost revenue" should be modified to conform to the definition include in 4 CSR Chapter 22. Commission Rule 4 CSR 240-22.020(38) reads: "Lost margin or lost revenues means the reduction between rate cases in billed demand (kW) and energy (kWh) due to installed demand-side measures, multiplied by the fixed-cost margin of the appropriate rate component." MEDA sees no reason to have differing definitions in the commission's regulations.

Staff, on the other hand, does not believe that the Chapter 22 definition is appropriate because:

(1) The language as drafted is "permissive" in nature and provides for the opportunity for recovery of lost revenues, rather than a guarantee. The proposed MEDA language is more explicit regarding the ability to recover lost revenues.

(2) Staff opposes MEDA's proposed use of Chapter 22's definition of lost revenue, because the Chapter 22 definition is used exclusively to exclude lost revenues from the definitions of annualized costs for end-use measures, from the definition of costs for the utility cost test, and from the definition of costs for the total resource cost test. Chapter 22 does not contemplate the use of its definition of lost revenue for any other purposes and it should not be assumed to be an appropriate definition for the MEEIA rules.

(3) The MEDA language also removes the requirements for evaluation measurement and verification (EM&V) of DSM program results prior to recovery of lost revenue and, therefore, allows for recovery of lost revenues on a prospective basis without any measurement and verification of DSM program results by an independent evaluator. Staff believes that if recovery of lost revenue is included in the MEEIA rules, measurement and verification of lost revenues should be required and should only be accomplished through independent EM&V on a retrospective basis. Lost revenues are based on energy usage that did not occur. In Staff's opinion, it is not appropriate to increase customer's rates on guesses as to what the customers who participated in the programs would have used absent the programs without a rigorous EM&V conducted by an independent evaluator.

Staff makes the following recommendation for clarifying the definition of "lost revenues." Staff also proposes changes in the language of the interrelated rule, 4 CSR 240-20.093(2)(G).

Lost revenue means the net reduction in utility retail revenue, taking into account all changes in costs and all changes in any revenues relevant to the Missouri jurisdictional revenue requirement, that occurs when utility demand-side programs approved by the commission in accordance with 4 CSR 240-20.094 cause a drop in net <u>system</u> retail KWh <u>delivered to jurisdictional customers</u> below the level used to set the electricity rates. Lost revenues are only those net revenues lost due to energy and demand savings from utility demand-side programs approved by the commission in accordance with 4 CSR 240- 20.094 Demand-Side Programs and measured and verified through EM&V.

Staff's proposed change would apply to definition section 4 CSR 240-20.094(1)(U) of this proposed rule and the following sections of the interrelated proposed rules: 4 CSR 240-3.163(1)(Q), 4 CSR 240-3.164(1)(M), and 4 CSR 240-20.093(1)(Y).

RESPONSE AND EXPLANATION OF CHANGE: The commission believes Staff's proposed revision to the current definition of lost revenue is appropriate and rejects MEDA's proposed revision for the reasons stated by Staff. The commission will modify 4 CSR 240-3.163(1)(Q), 4 CSR 240-3.164(1)(M), 4 CSR 240-20.093(1)(Y), and 4 CSR 240-20.094(1)(U) accordingly.

COMMENT # 4 – INCONSISTENT DEFINITIONS FOR DESIGNATION OF UTILITY'S REQUEST FOR APPROVAL OF A DEMAND-SIDE PROGRAM:

In order to clarify language in the interrelated rules related to filing a request for approval of a demand-side program, Staff recommends the following definition be included in 4 CSR_240-3.163, 4 CSR 240-20.093, and 4 CSR 240-20.094: "Filing for demand-side program approval means a utility's case filing for approval, modification or discontinuance of demand-side program(s) which may also include a simultaneous request for the establishment, modification or discontinuance of a DSIM."

After adopting this definition, the following inconsistent terms require clarification:

1) "utility's filing for demand-side program approval" found in 4 CSR 240-3.163(1)(I) and 4 CSR 240-20.093(1)(P).
2) "utility's filing for demand-side program approval proceeding" found in 4 CSR 240-3.163(1)(F), (G), (J), and (K); 4 CSR 240.20.093(1)(M), (N), (Q), (R) and (DD); and 4 CSR 240-20.094 (1) (J), (L), (M) and (N).
3) "demand-side program approval proceeding" found in 4 CSR 240-3.163(9), (9)(A) and (B); 4 CSR 240-20.093(1)(I), (DD); and 4 CSR 240-20.093(1) (I), (2), (2)(G)2, (3)(B), (4) and(10).
4) "application for demand-side program approval proceeding" found in 4 CSR 240-20.093(2)(B).

Due to the lack of a definition and the use of inconsistent terminology, it is unclear whether a "filing", "application" or "proceeding" is intended to occur. Therefore, Staff recommends that if this language remains in the proposed MEEIA rules, that the recommended definition for the phrase "filing for demand-side program approval" be utilized and that consistent terminology be used throughout the proposed MEEIA rules as indicated above.

RESPONSE AND EXPLANATION OF CHANGE: The commission agrees this language should be clarified, but it also believes that inclusion of the word "case" in Staff's recommended definition could also add confusion. Consequently, the commission will adopt the following definition and clarify the identified terms for this proposed rule:

Filing for demand-side program approval means a utility's filing for approval, modification or discontinuance of demand-side program(s) which may also include a simultaneous request for the establishment, modification or discontinuance of a DSIM.

COMMENT # 5 – DEFINITION OF PROBABLE ENVIRONMENTAL COST

MDNR, NRDC, Sierra Club, Renew Missouri, GRELC state that the statutory definition of the Total Resource Cost test ("TRC") includes "probable environmental compliance costs." § 393.1075.2(6). The proposed rules do not define or even use this term but incorporate instead the definition of "probable environmental costs" from the proposed IRP rule, 4 CSR 40-22.020(46). See 4 CSR 240-3.163(1)(Q), 4 CSR 240-3.164(1)(R), 4 CSR 240-20.093(1)(Y) and 4 CSR 240-20.094(1)(V). The proposed rule 22.040(2)(B) does not provide an adequate method of calculating environmental compliance costs. It is restricted to future costs associated with a selected list of pollutants which, in the judgment of utility decision makers, could have a significant effect on rates. SB 376 plainly means to include all costs, including present costs, and a more objective assessment, not one based on "subjective probability" in certain individuals' judgment. The Commission needs to include a methodology in its rules for calculating these costs, which might include an environmental cost adder expressed in dollars or, as in Ohio, a percentage externality factor. Relying on the IRP rule to implement SB 376 has the effect of adding criteria such as the subjective judgment of utility decision makers that, as discussed above, are not in the statute.

Related to these concerns, OPC's proposed changes to the definition of the TRC as follows: Total resource cost test or TRC means the test that compares the avoided utility costs (including probable environmental compliance costs) to the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions), plus utility costs to administer, deliver and evaluate each demand-side ~~program to quantify the net savings obtained by substituting the demand-side program for supply-side resources.~~ The present value of the program avoided utility benefits shall be calculated over the projected life of the measures installed under the program.

RESPONSE AND EXPLANATION OF CHANGE: The concerns raised by these stakeholders regarding the definitions and relationships between the terms TRC, avoided cost or avoided utility cost and probable environmental compliance cost are inter-related to OPC concerns with the definition of TRC echoed in Comment 17 in proposed rule 4 CSR 240-20.093. Consequently, the commission will address both of these concerns in its response to each comment.

The current proposed rules 4 CSR 240-3.163(1); 4 CSR 240-3.164(1); 4 CSR 240-20.093(1) and 4 CSR 240-20.094(1) have the following definitions:

Avoided cost or avoided utility cost means the cost savings obtained by substituting demand-side programs for existing and new supply-side resources. Avoided costs include avoided utility costs resulting from energy savings and demand savings associated with generation, transmission, and distribution facilities. The utility shall use the same methodology used in its most recently-adopted preferred resource plan to calculate its avoided costs;

Probable environmental cost means the expected cost to the utility of complying with new or additional environmental legal mandates, taxes, or other requirements that, in the judgment of the utility's decision-makers, may be imposed at some point within the planning horizon which would result in compliance costs that could have a significant impact on utility rates. The utility shall use the same methodology used in its most recently-adopted preferred resource plan to calculate its probable environmental costs;

Total resource cost test, or TRC, means the test of the cost-effectiveness of demand-side programs that compares the avoided utility costs plus avoided probable environmental cost to the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions), plus utility costs to administer, deliver, and evaluate each demand-side program to quantify the net savings obtained by substituting the demand-side program for supply-side resources.

Section 393.1705 (6) defines "Total resource cost test", as a test that compares the sum of avoided utility costs and avoided probable environmental compliance costs to the sum of all incremental costs of end-use measures that are implemented due to the program, as defined by the commission in rules.

The commission believes the following redline revisions to the definitions in 4 CSR 240-3.163(1)(C),(R), and (T); 4 CSR 240-3.164(1)(A), (R) and (X); 4 CSR 240-20.093(F), (Z) and (DD); and 4 CSR 240-20.094(1)(D), (W), and (Y) address the concerns expressed by OPC and by MDNR, NRDC, Sierra Club, Renew Missouri, and GRELC:

Avoided cost or avoided utility cost means the cost savings obtained by substituting demand-side programs for existing and new supply-side resources. Avoided costs include avoided utility costs resulting from <u>demand-side programs'</u> energy savings and demand savings associated with generation, transmission, and distribution facilities <u>including avoided probable environmental compliance costs</u>. The utility shall use the same methodology used in its most recently-adopted preferred resource plan to calculate its avoided costs;

Probable environmental <u>compliance</u> cost means the expected cost to the utility of complying with new or additional environmental legal mandates, taxes, or other requirements that, in the judgment of the utility's decision-makers, may be imposed at some point within the planning horizon which would result in <u>environmental</u> compliance costs that could have a significant impact on utility rates. ~~The utility shall use the same methodology used in its most recently-adopted preferred resource plan to calculate its probable environmental costs~~;

Total resource cost test, or TRC, means the test of the cost-effectiveness of demand-side programs that compares the avoided utility costs ~~plus avoided probable environmental cost~~ to the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions), plus utility costs to administer, deliver, and evaluate each demand-side program ~~to quantify the net savings obtained by substituting the demand-side program for supply-side resources~~.

Additionally, the commission chooses to not include a methodology in its MEEIA rules for calculating probable environmental compliance costs. The commission notes that subsection (10) of the proposed rule requires the commission to complete a review of the effectiveness of this rule no later than four years after the effective date at which time it may initiate rulemaking proceeding to revise the rule. Upon review, the commission will have the opportunity to revisit this issue to determine if it is appropriate to include a methodology. The commission's actions on the definitions of avoided cost, probable environmental compliance cost and total resource cost test are consistent with the commission's actions regarding the interaction between this rule and 4 CSR 240-22 Electric Utility Resource Planning.

COMMENT # 6 – DEFINITION OF STAFF:

Staff believes that the word 'Staff" in 4 CSR 240-20.094(1) is too broadly defined In the proposed rule. The term Staff is currently defined as, "all commission employees, except the secretary of the commission, general counsel, technical advisory staff as defined by section 386.135, RSMo, hearing officer, or regulatory judge." The definition of Staff in each of the draft rules would include attorneys in the Office of the General Counsel other than the General Counsel who are not in the Office of the Staff Counsel. Staff is not certain that result is intended. The definitions appear at 4 CSR 240-3.163(1)(S), 4 CSR 240- 3.164(1)(V), 4 CSR 240-20.093(1)(BB) and 4 CSR 240-20.094(1)(X).

RESPONSE AND EXPLANATION OF CHANGE: The commission agrees with Staff. Not only did the commission not intend to include attorneys in the Office of the General Counsel other than the General Counsel who are not in the Office of the Staff Counsel, but the commission will conform the definition of "Staff" to that being formulated in the commission's Chapter 2 revisions in order to maintain consistency throughout all of its rules. "Staff" will be defined as:

Staff means all personnel employed by the commission, whether on a permanent or contract basis, except: commissioners, commissioner support staff including technical advisory staff, personnel in the secretary's office, and personnel in the general council's office including personnel in the adjudication department. Employees in the staff's counsel's office are members of the commission's staff.

COMMENT # 7 – GUIDELINES TO REVIEW PROGRESS TOWARD AN EXPECTATION THAT THE ELECTRIC UTILITY'S DEMAND-SIDE PROGRAMS CAN ACHIEVE A GOAL OF ALL COST-EFFECTIVE DEMAND-SIDE SAVINGS (GENERALLY)

Numerous comments were filed in relation to 4 CSR 240-20.094(2)(A) and (B). Some supported the guidelines established in the proposed rules, some recommended adjustments, while others opposed them completely. The commission will consolidate the generally focused comments for purposes of its response, but it will examine other specific language not related to the general comments in other comment sections

MIEC believes the provisions of the draft rules regarding incremental and cumulative goals for the utility programs are unlawful because these provisions are not authorized by statute. The targets are completely arbitrary and lack foundation. The provision requires that the energy savings and demand savings should be the ". . . greater of the annual realistic achievable energy savings and demand savings determined through the utility's market potential study or the following incremental annual demand-side savings goals . . .", which MIEC believes is patently unreasonable.

The MEDA members believe 4 CSR 240-20.094(2)(A) and (B) identify incremental and cumulative goals for energy efficiency programs that are not authorized by the MEEIA and are unlawful. MEDA believes the proposed goals appear to have been developed without any utility-specific analyses and are inconsistent with current potential studies. If goals are to be applied, if permissible by law, MEDA believes they should be linked to reasonable and achievable savings goals supported by utility-specific potential studies.

MDNR, NRDC, Sierra Club, Renew Missouri, GRELC support inclusion of numerical efficiency targets, which they believe would represent reasonable progress toward the goal of capturing all cost-effective energy efficiency in Missouri. The savings goals are not "hard" targets; thus, if for some reason the utility's potential studies demonstrate clearly that these targets are out of reach, the Commission may approve a plan that falls short of the targets. However, the targets provide a backstop to guard against a utility-controlled potential study that may significantly underestimate the available energy savings potential in order to establish a lower baseline for the purposes of a performance incentive. In other words, allowing the Commission to use targets that reflect levels of savings that have been adopted broadly throughout the region, as well as potential studies that take into account the unique aspects of any particular service territory, strikes the appropriate balance for Missouri.

NRDC specifically refers the commission to targets and goals set in Indiana, Illinois, Iowa, New Mexico and Ohio to demonstrate that the proposed rule set reasonable targets to achieve reasonable progress toward all cost effective energy efficiency. NRDC states there are 24 states with energy efficiency savings targets, either mandatory or goals, and either statutory or commission-adopted. NRDC directs the commission to a fact sheet prepared by the American Council for an Energy-Efficient Economy to review these states' programs.

OPC is concerned that the ramp up rate of these annual energy and peak demand savings goals may be too steep in years two (2013) through four (2015) and recommends that the rate be decreased in these years. The goals proposed by Public Counsel in years two (2013) and three (2014) are consistent with the goals in the revised energy efficiency rule currently being considered by the Texas Public Utility Commission (PUC) in its rulemaking designated as Project No. 37623. In years three (2014) and four (2015), OPC's suggested goals increase by an increment of .15% per year, rather than .2%, and in year five (2016) and thereafter, the annual energy goals increase at the same .2% increment reflected in the proposed rules. Under OPC's proposal, the cumulative reductions in annual energy are decreased relative to the cumulative annual energy reduction amounts in the proposed rule due to the lower increments of increase that occur in years two, three, and four. Public Counsel has also proposed changes to the annual peak demand savings goals to moderate the ramp up rate in years one (2012) through three (2014). The annual peak demand savings goals in years one, two and three have been lowered from the proposed level of 1% in each year to .7%, .8%, and .9% respectively. In year four (2015) and thereafter, the annual peak demand savings goals return to the same 1% increment found in the proposed rule. Corresponding changes to the cumulative annual energy and peak demand savings goals that appear in Subsection (2)(B) of the proposed rule have also been made to the attached rules containing OPC's recommended changes.

Public Counsel has a couple of additional concerns with annual energy and peak demand savings goals that are set forth in Subsection (2)(A) of the rule. The rule does not specify how the savings goals that would apply for each utility should be calculated. OPC believes that the numbers used to calculate the goals should be weather normalized and that the numbers relied on to determine the extent to which each utility has met the goals should also be weather normalized. Perhaps the rule drafters assumed there was no need to specify this in the rule. However, OPC believes this would help reduce the potential for future differences over how this portion of the rule should be applied. The rule also fails to specify the base or numerator that would be used to calculate the goals that would apply to each utility and to the calculation of the utility's performance relative to the goals. If weather normalized numbers are used, it may be appropriate to simply use the prior year's weather normalized annual energy and peak demand in order to calculate the amount of annual energy (MWhs) and annual peak demand (MWs) that correspond to the percent savings goals in each year for a particular utility.

Staff supports the inclusion of the currently drafted annual energy and demand savings *targets* as defined in proposed rule 4 CSR 240-20.094 and the incremental and cumulative annual energy and demand savings *goals* specified in proposed rule 4 CSR 240-20.094(2), and the associated distinction in the proposed language. Staff views the distinction between the incremental and cumulative annual energy and demand savings *goals* as "soft goals" and the annual energy and demand savings *targets* as "hard goals" is appropriate.

According to Staff, there is a distinction between the annual energy savings *targets* and annual demand savings *targets* as defined in proposed 4 CSR 240-20.094 versus the incremental annual energy and demand savings *goals* and cumulative annual energy and demand savings *goals* specified in proposed 4 CSR 240-20.094(2). The *goals* specified in 4 CSR 240-20.094(2) are not tied to the utility incentive component of a DSIM. Moreover, the *goals* in 4 CSR 240-20.094(2) are not a mandate and may be informed by the utility's demand-side management (DSM) market potential study required by 4 CSR 240-3.164(2)(A). The *goals* in 4 CSR 240-20.094(2) along with the realistic achievable annual energy savings and annual demand savings as determined through the electric utility's market potential study required in 4 CSR 240-3.164(2)(A) shall provide guidance to the Commission and the electric utility for planning purposes and represent what could be viewed as reasonable progress towards achieving a statutory goal of achieving all cost effective demand-side savings. There are no incentives or penalties tied to the *goals* in 4 CSR 240-20.094(2). The annual energy savings *targets* and annual demand savings *targets* as defined in 4 CSR 240-20.094 are approved by the Commission at the time of each demand-side program's approval. These *targets* are used in determining the utility's performance levels for the utility incentive component of a DSIM.

RESPONSE: Rulemaking is an exercise of the Commission's quasi- legislative power. Interim goals are well within the rulemaking authority granted to the commission in §393.1075.11. An administrative agency has reasonable latitude regarding what methods and procedures to adopt in carrying out its statutory duties. The legislative delegation of powers and duties includes by implication everything necessary to carry out the power or duty and make it effectual or complete. "Where the grant of power is clear, the detail for its exercise need be given only within practical limits. The rest may be left to the administrative agency delegated the duty to accomplish the legislative purpose." *AT&T v. Wallemann*, 827 S.W.2d 217, 224-225 (Mo. App. WD 1992). Moreover, the "soft-goals" at issue are guidelines to review progress and are not mandatory.

During the workshops for the proposed rule, the comment period and the rulemaking hearing, information regarding the targets and goals employed in other states was presented to the commission, including, but not limited to, targets and goals in the states of Illinois, Indiana, Iowa, Kentucky, Michigan, Minnesota, Ohio and Wisconsin. Based upon this information, and the level of DSM currently implement by Missouri utilities, the commission's staff believed that the initial goals supported by MDNR, GRELC and NRDC were too aggressive and it reduced the goals to the current levels delineated in the proposed rule. As the rules are currently drafted, if the annual incremental and cumulative energy and demand savings differ from the results of the utility's potential study, the commission has the ability to use the utility-specific results of the potential study as a guideline to review progress toward an expectation that the electric utility's demand-side programs can achieve a goal of all cost-effective demand-side savings. If the goals in the proposed rule are used as opposed to the utility's own potential study, they too are merely a guideline to review progress. Because the goals are not mandatory, OPC's concern about them being too steep is unfounded. The commission will make no changes to the language identified by these comments in the proposed rule in relation to the goals contained in 4 CSR 240-094(2)(A) or (B).

With regard to OPC's concern about ramping the annual energy and peak demand savings goals too quickly, the best way to evaluate the reasonableness of the current 094(2) goals and those proposed by OPC is to compare both sets of goals to the realistic achievable potential ("RAP") for energy savings and for demand savings in the Ameren Missouri DSM Market Potential Study (which is public information and was conducted using primary data collected from Ameren Missouri's customers and was published in January 2010).

The current 094(2)(A) states: The commission shall use the greater of the annual realistic achievable energy savings and demand savings as determined through the utility's market potential study or the following incremental annual demand-side savings goals as a guideline to demonstrate that the electric utility's demand-side programs are expected to achieve all cost-effective demand-side savings.

The current 094(2)(B) states: The commission shall use the greater of the cumulative realistic achievable energy savings and demand savings as determined through the utility's market potential study or the following cumulative demand-side savings goals as a guideline to demonstrate that the electric utility's demand-side programs are expected to achieve all cost-effective demand-side savings.

Analyzing that the current proposed 094(2)(A) and (B) goals demonstrates that the OPC's recommended goals should be rejected because:

1. The Ameren RAP cumulative energy savings potential is clearly greater than the current proposed 094(2)(A) cumulative energy savings goal in 2015, so the OPC recommended goals would not come into play through 2015.

2. Although the Ameren RAP cumulative energy savings potential is less that either the current proposed 0949(2)(A) cumulative energy savings goal in 2020 or the OPC recommended alternative, under the current proposed 094(2)(A) the commission would choose the greater of annual RAP energy savings as determined through the utility's market potential study or the annual cumulative energy savings goals to demonstrate that the electric utility's demand-side programs are expected to achieve all cost-effective demand-side savings. Thus, the commission would determine what a reasonable annual and cumulative energy savings goal is for Ameren each year from 2015 to 2020. There would like be a transition at some point in time from the Ameren energy savings potentials in 2015 to the 094(2)(A) energy savings goals in 2020.

3. The Ameren RAP cumulative demand savings potential is clearly greater than the current proposed 094(2)(B) cumulative demand savings goal in 2015 and in 2020, so the OPC recommended goals would not come into play through 2020.

The commission will not adopt any changes to the current language in these subsections of the proposed rule.

The commission notes that it is possible that the commission will amend this rule in the future to modify these goals. Indeed, 4 CSR 240-20.094(10) mandates a complete review of the effectiveness of this rule no later than four years after the effective date. The Utility-Specific and State-Wide Collaboratives to be mandated in 4 CSR 240-20.094(8) will be invited to make any suggested modifications during the review process.

COMMENT # 8 – GUIDELINES TO REVIEW PROGRESS TOWARD AN EXPECTATION THAT THE ELECTRIC UTILITY'S DEMAND-SIDE PROGRAMS CAN ACHIEVE A GOAL OF ALL COST-EFFECTIVE DEMAND-SIDE SAVINGS (SHARED SAVINGS MECHANISM)

OPOWER, Inc. recommends:

(1) Adopting "clear and meaningful" efficiency targets – it points to Illinois, Minnesota and Arkansas as examples and believes the guidelines in this proposed rule should be adopted.

(2) Creation of a framework where utilities can receive a performance incentive for exceeding the targets and specifically define the performance incentives – it points to sharing savings mechanism used in Oklahoma, California and Minnesota as examples.

OPOWER notes that the commission has proposed a performance incentive (a shared savings incentive model) to allow utilities to receive a percentage of the net benefits of energy efficiency programs, but recommends that the MO PSC build on this proposal and define the exact performance incentive to reward utilities. It is important that approval of incentives and associated cost and lost revenue recovery be provided expeditiously to utilities so as to minimize uncertainty. Providing certainty and timeliness will allow utilities to better incorporate efficiency programs into their bottom line and reduce business risk. Such an approach will serve both ratepayers and shareholders alike.

OPOWER points to the following performance incentives as potential models for the MO PSC to explore. Keeping in mind that the PSC has already identified the shared savings model, OPOWER has focused its examples around that type of incentive. OPOWER firmly believes that the final incentive mechanism adopted by the PSC will reflect the Missouri regulatory landscape. OPOWER is not suggesting that Missouri adopt any these exact mechanisms. They wish simply to point out other shared savings incentive structures that have been adopted in other states that may provide some insights:

- Shared Savings Mechanism I (Oklahoma): The Oklahoma regulator has approved a different type of shared savings mechanism for both Oklahoma Gas and Electric (OG&E) and PSO (AEP). OG&E can earn up to 25% of net benefits for each measure with a Total Resource Cost (TRC) of greater than 1.0 and 15% of net benefits for programs where TRC is less than 1.0. PSO may earn up to 25% net benefits for programs where "savings can be estimated" and 15% for other programs where savings cannot be accurately identified (i.e., education and marketing programs). This incentive structure has had the desired effect of rapidly ramping up efficiency programs in Oklahoma.

- Shared Savings Mechanism II (Minnesota): In 2010 Minnesota revamped its incentive structure to a shared savings mechanism. When a utility achieves energy savings equal to 1.5% of retail sales, electric utilities will earn 0.09 cents for each kWh saved, and gas utilities will earn 4.50-6.50 times the number of Mcf saved.

- Shared Savings Mechanism III (California): Utilities are able to earn back a percentage of net benefits based on what percentage of goals they achieve:
    - Over 100%: If the utilities achieve this threshold of savings, then utilities can achieve 12% of net benefits.
    - 85%-100%: If the utilities achieve this threshold of savings, then utilities can receive 9% of net benefits. (In this context "net benefits" means monetary benefits to the consumer, or, in other words, how much consumers save on energy efficiency.)
    - 65-85%: No earnings or penalties
    - 0-65%: Utilities are penalized 5 cents/kWh, $25/KW, 45 cents/therm below goals (penalties capped at $450 million per utility).

  The advantage of this incentive structure is that it rewards utilities for strong performance, while only penalizing utilities for severely underperforming.

(3) Development of a comprehensive set of guidelines to measure the impact of energy efficiency programs, known as a Technical Resources Manual.

To encourage transparent, verifiable energy savings, MO PSC should develop a comprehensive set of guidelines for measuring the impact of energy efficiency programs, also known as a Technical Resource Manual (TRM). A TRM defines the proper method for calculating savings for specific measures across the residential, commercial, and industrial sectors. A Missouri TRM would provide the PSC and MO taxpayers with clearer insight into how estimates of energy savings are generated. Regulators in states with Technical Resources Manuals, including Pennsylvania, Vermont, and Massachusetts, are more confident than those without them that the efficiency savings claimed by their utilities are real and verified.

Measures typically fall into two broad categories:

- *Asset-based (installed measures)*: algorithms are assigned for each individual measure in order to calculate deemed savings values. Examples of asset-based programs include CFL light bulbs, energy efficient appliances, and electric motors.

- *Non-Asset based (non-installed measures):* for programs where a deemed savings approach is insufficient or not feasible, the TRM establishes protocols for how to measure program setup and net impact. Examples of non-asset based programs include behavior-based programs, home energy audits, and large-scale plant expansions.

A TRM not only provides clarity in measuring and reporting savings, but also regulatory certainty for all stakeholders. In short, a TRM ensures that ratepayer money is being spent to generate cost-effective savings that provide net economic benefits to ratepayers.

RESPONSE AND EXPLANATION OF CHANGE: OPOWER agrees that the commission has proposed a performance incentive (a shared savings incentive model) to allow utilities to receive a percentage of the net benefits of energy efficiency programs and the commission has established a framework for lost revenue recovery. The commission does not believe it is beneficial to attempt to be more exact with regard to performance incentives to reward utilities at this time. Rather, it is best to allow the maximum amount of flexibility to structure these mechanisms. Nothing precludes the commission from considering shared savings incentive structures on a case-by-case basis as it considers individual mechanisms.

With regard to the TRM, the commission supports the current proposed language in 4 CSR 240-20.094(8)(B). The commission prefers a statewide technical resource manual which is encouraged in 094(8)(B) through the stakeholder process. The commission believes the proposed rule makes the appropriate step towards achieving the goal of all cost-effective demand-side savings and will not alter the proposed rule to make it more specific or comprehensive at this time.

The commission appreciates OPOWER's comments and emphasizes that it is not foreclosing any options for future revisions. As was noted in the response to Comment # 7, it is possible that the commission will amend this rule in the future to modify these goals. Indeed, 4 CSR 240-20.094(10) mandates a complete review of the effectiveness of this rule no later than four years after the effective date.

In the process of reviewing the issue concerning the TRM the commission noticed some internal inconsistencies with the way the inter-related rules made reference to the TRM. In some sections it referred to the TRM as the "technical resource manual" and in others it referred to the TRM as the "technical reference manual." The proper designation is "technical resource manual" and the commission will correct language in the following sections of the MEEIA rules 4 CSR-20.093(1)(CC) and (7)(E); and 4 CSR 240-20.094(C) and (8)(B).

COMMENT # 9 – GUIDELINES TO REVIEW PROGRESS TOWARD AN EXPECTATION THAT THE ELECTRIC UTILITY'S DEMAND-SIDE PROGRAMS CAN ACHIEVE A GOAL OF ALL COST-EFFECTIVE DEMAND-SIDE SAVINGS (ACHIEVABLE VERSUS REALISTIC ACHIEVABLE LANGUAGE)

MDNR, NRDC, Sierra Club, Renew Missouri, and GRELC believe that 4 CSR 240-20.094(2)(A) and (B) should simply refer to "achievable" instead of "realistic achievable" energy savings and demand savings. A utility can use either realistic achievable potential or the numeric goals in demonstrating progress toward the statutory goal of "all cost-effective demand side savings" pursuant to 20.094(2)(A)and (B). Given the potentially critical role of the utility potential study in creating the performance goals and subsequently determining the level of performance incentive, it is important that the potential study be conducted in a collaborative way that provides confidence in its results.

The definitions of potential in the proposed rule, taken together, could significantly and adversely influence Commission review of progress toward the legislative goal of "achieving all cost-effective demand-side savings" as well as future utility conduct of potential studies. The core distinction in NAPEE's Guide is between "achievable potential" and "program potential." As NAPEE uses the terms, "achievable potential" takes expected program participation into account and is the reference point for considering various levels of "program potential" that are based on different levels of utility funding and implementation. This is in contrast to an assumption of an absolute distinction between "maximum" and "realistic" achievable potential that introduces an analytic weakness and which does not acknowledge that there can be many levels of "achievable potential" based on the level of funding and aggressiveness of implementation that the company elects to pursue. Estimates from a market potential study are highly variable, depending on the measures included in a study, the range of customer incentives considered in the study questionnaires, and the assumptions used to calculate energy savings forecasts. Using the current definitions in the proposed rule could result in the following adverse consequences: (1) The draft language could limit the Commission's view of the potential for cost-effective demand side savings to the level of funding and aggressiveness of implementation that the company elects to assume in its potential study; (2) Future utility potential studies could focus unduly on establishing a single level of "realistic" achievable potential, limiting their study of the range of options under different levels of program implementation. This would be most likely to occur if the rule requires the utility to conduct potential studies but fails to establish adequate standards for conducting them.

RESPONSE: Similar to the commission's response concerning the proposed changes to definitions of economic, technical, realistic, maximum achievable, in inter-related rule 4 CSR 240-3.0164, adopting this proposed change will result in the most aggressive DSM program scenarios possible. The commission believes this will result in an expectation of very high goals that are unrealistic or unattainable in the early stages of implementing the MEEIA. The commission will not substitute or change the current definitions of these terms.

COMMENT # 10 – GUIDELINES TO REVIEW PROGRESS TOWARD AN EXPECTATION THAT THE ELECTRIC UTILITY'S DEMAND-SIDE PROGRAMS CAN ACHIEVE A GOAL OF ALL COST-EFFECTIVE DEMAND-SIDE SAVINGS (PENALTY LANGUAGE)

The MEDA stakeholders believe that the sentence in 4 CSR 240-20.094(2) reading: "The fact that the electric utility's demand-side programs do not meet the incremental or cumulative annual demand-side savings goals established in this section may impact the utility's DSIM revenue requirement but is not by itself sufficient grounds to assess a penalty or adverse consequence for poor performance" is offensive to the language in Section 393.1975.3 that positively encourages demand-side investment. MEDA states there is no language in the statute authorizing the implementation of penalties or adverse consequences and this language should be deleted.

RESPONSE AND EXPLANATION OF CHANGE: The commission agrees and this language shall be removed. Additionally, the commission will add the following language to this section:

<u>The goals established in this section are not mandatory and no penalty or adverse consequence will accrue to a utility that is unable to achieve the listed annual energy and demand savings goals.</u>

COMMENT # 11 – APPLICATIONS FOR APPROVAL OF ELECTRIC UTILITY DEMAND-SIDE PROGRAMS OR PROGRAM PLANS

MEDA is concerned that the following language used in 4 CSR 240-20.094(3) is unclear:

> . . . Any existing demand-side program with tariff sheets in effect prior to the effective date of this rule shall be included in the initial application for approval of demand-side programs if the utility intends for unrecovered and/or new costs related to the existing demand-side program be included in the DSIM cost recovery revenue requirement, . . .

MEDA believes the language in this section must be clarified to ensure that any transition from existing demand-side programs in effect pursuant to an existing and approved tariff sheet must ensure the recovery of lawfully approved and unrecovered costs, particularly in the event that such tariffed program is being discontinued.

RESPONSE: For clarity the commission notes that DSM programs have tariffs currently and under the proposed MEEIA rules programs will have tariffs, DSM plans do not and will not have tariffs. See 20.094(3)(D). The language of the proposed rules is clear when it says "if the utility intends for unrecovered and/or new costs related to the existing demand-side program be included in the DSIM cost recovery revenue requirement" that the intent is to allow recovery of programs that are already tariffed, as long as they are included in the application for program approval. The commission finds no reason to modify the current language in this subsection.

COMMENT # 12 – THE INTERPLAY BETWEEN THIS RULE AND 4 CSR 240-CHAPTER 22, ELECTRIC UTILITY RESOURCE PLANNING

MDNR, NRDC, Sierra Club, GRELC, and Renew Missouri have expressed concerns regarding the interplay between the proposed rules to implement MEEIA and the commission's Chapter 22 rules involving integrated resource planning ("IRP"). These concerns implicate proposed rules 4 CSR 240-3.164(2)(B)(3) (filing and submission requirements) and 4 CSR 240-20.094(3)(A)3 (demand-side programs). Consequently, the commission will address those comments in both rules.

MDNR, NRDC, Sierra Club, Renew Missouri, GRELC would like for proposed rules, 4 CSR 240-3.164(2)(B)(3) and 4 CSR 240-20.094(3)(A)3 to be eliminated. Rule 4 CSR 240-20.094(3)(A)3 says the PSC must approve programs that pass the Total Resource Cost Test, but it adds the following condition, that the programs: "Are included in the electric utility's preferred plan or have been analyzed through the integration process required by 4 CSR 240-22.060 to determine the impact of the demand-side programs and program plans on the net present value of revenue requirements of the electric utility." However, the criterion of the MEEIA is the cost effectiveness of demand-side programs. § 393.1075.3–.4. Under the latest Chapter 22 rewrite, the primary criterion is the minimization of utility costs, but utilities may use other critical factors. 22.010(2). The most cost effective demand-side portfolio could fail the IRP tests if it were packaged with a bad set of supply-side resources.

Selection of a preferred resource plan (PRP) is contingent on the policy objectives and performance measures and also on the judgment of utility decision-makers. 22.070(1). While it would appear from 22.070(1)(C) that a PRP will maximize demand-side resources, it is not clear how the winnowing of ARPs assembled under 22.060 will automatically yield a PRP with the most cost-effective demand-side portfolio; the minimally compliant ARP of 22.060(3)(A)1 and the optimally compliant ARP of 22.060(3)(A)5 could both fail during the analysis prescribed in 22.060(4)–(7). Furthermore even the demand-side component of the PRP is subject to the judgment of utility decision-makers; they decide whether the PRP is in the public interest and achieves state energy policies. 22.070(1)(C). Lowest PVRR, IRP policy objectives, performance measures, critical uncertain factors and decision-makers' judgment are all criteria absent from the MEEIA.

According to MDNR, NRDC, Sierra Club, Renew Missouri, GRELC, there is a disconnect between 22.060 and 22.070: 4 CSR 240.22.060(3)(A)1–5 prescribes a special set of alternative resource plans for renewable and demand-side resources. These include a minimally compliant demand-side plan (the "compliance benchmark"), an "aggressive" plan defined as maximum technical potential (which is an academic exercise), and an optimally compliant plan (minimal compliance with legal mandates but maybe something more).

It's unclear what happens to these plans. They must go through the analysis of 22.060(4)–(7). The preferred resource plan must use demand-side resources to the "maximum" amount that complies with legal mandates. 22.070(1)(C). This differs from both the minimal compliance benchmark ARP and the "optimal" ARP. Indeed, 22.070 does not even say that the PRP must be one of the ARPs in 22.060.

According to MDNR, NRDC, Sierra Club, Renew Missouri, GRELC, the status of the PRP is uncertain. The PRP is a moving target. It can change at any time and be replaced by a contingent plan if the PRP ceases to be appropriate for any reason. 22.070(4). The PRP can become obsolete if it ceases to be consistent with the utility's business plan or acquisition strategy. 22.080(12). A utility can get variances from the rule. 22.080(13). A utility may request action in other cases that is inconsistent with the PRP as long as it provides a detailed explanation. 22.080(17). Under the MEEIA rule, 20.094(3)(A)3,the utility can disregard the PRP, but whatever programs it offers must first go through 22.060 integration, which still involves all the criteria itemized above that are not in the MEEIA.

According to MDNR, NRDC, Sierra Club, Renew Missouri, GRELC, MEEIA outranks Chapter 22. If the IRP rule is to perform that role, it must be modified to accommodate the MEEIA. SB 376 is a delegation of specific rulemaking authority to achieve the MEEIA's purposes. § 393.1075.11. Chapter 22, by contrast, has no specific legislative authority. Its status as an internal Commission rule is reflected in the limited, procedural nature of the Commission's review of utility IRPs: only deficiencies in Chapter 22 compliance are reviewable, not the substance of the plans. 22.080 (7, 8, 16).

According to MDNR, NRDC, Sierra Club, Renew Missouri, GRELC, MEEIA, if the commission subordinates the MEEIA to Chapter 22, it will be imposing criteria not prescribed by the legislature and will be unlawful. The commission cannot use its general rulemaking powers under §§ 386.250(6) and 393.140(11) to make rules inconsistent with the MEEIA. To do so would be to exercise a legislative function in violation of the separation of executive from legislative powers. Mo. Constitution Article II, § 1. Chapter 22 and the MEEIA can only be harmonized by ensuring that a demand-side portfolio that satisfies the criteria of the MEEIA automatically becomes part of the preferred resource plan, not the other way around.

Staff responded to these concerns in the following manner:

Various groups expressed opposition regarding the requirement that proposed demand-side programs be analyzed through the integration analysis process required by Chapter 22 Electric Utility Resource Planning. Some of the concerns expressed by these stakeholder organizations were that the process is a burdensome requirement and that it may not result in a set of demand-side resources that are adequate to meet a MEEIA goal of achieving all cost-effective demand-side savings; therefore, the results of the Chapter 22 integration analysis process should not be a limiting factor in the approval of the demand-side programs submitted under the proposed 4 CSR 240-20.094 rule. These stakeholder groups contend that the Total Resource Cost (TRC) test should be an adequate measure, by itself, to determine which demand-side programs are proposed and approved. Staff does not agree with the concerns of these stakeholder groups.

According to Staff, Missouri's Chapter 22 Electric Utility Resource Planning rules are expected to continue to result in an ongoing and dynamic electric utility resource planning process to "optimize" both supply-side resources and demand-side resources at the lowest cost to electricity ratepayers while taking into consideration risk and uncertainty associated with critical uncertain factors such as: future customer loads (for energy and for demand), future fuel and purchased power prices, future economic conditions, future legal mandates, and new technology. Simply using the TRC test to determine which demand-side programs are proposed and approved does not give any consideration to risk and uncertainty associated with critical uncertain factors. Proposed rule 4 CSR 240-20.094(3)(A) requires that proposed demand-side programs, "Are included in the electric utility's preferred [resource] -plan or have been analyzed through the integration process required by 4 CSR 240-22.060 to determine the impact of the demand-side programs and program plans on the net present value of revenue requirements of the electric utility." Staff supports this requirement as it places demand-side resources on an equal basis with supply-side resources. Section 393.1075.3 RSMo Supp. 2009, states that, "It shall be the policy of the state to value demand-side investments equal to traditional investments in supply and delivery infrastructure and allow recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs." The requirement that proposed demand-side programs be analyzed through the integration analysis process is consistent with MEEIA. Moreover, the requirement in proposed rule 4 CSR 240-20.094(3)(A) indicates that the integration analysis should be completed and filed as required by 4 CSR 240-3.164(2)(B)3., but does not state that the results would necessarily be a limiting factor in the approval of demand-side programs.

Finally, Staff would like to clarify for the Commission that should the electric utility determine that it wants to propose demand-side programs or program plans which are not included in the electric utility's preferred resource plan, a completely new Chapter 22 analysis and new preferred resource plan are not necessary. The only requirement of 4 CSR 240-20.094(3)(A) is that demand-side programs and program plans, "have been analyzed through the integration process required by 4 CSR 240-22.060 to determine the impact of the demand-side programs and program plans on the net present value of revenue requirements of the electric utility." Further, such integration analysis to determine the impact of individual demand-side programs on the net present value of revenue requirements of the electric utility have been requested by Staff during 2010 on several occasions for demand-side programs which were not in the preferred resource plans of the individual electric utilities. The electric utilities performed the integration analysis, reported the incremental change to the net present value of revenue requirements, and communicated to Staff that the integration analysis was not burdensome taking no more than a day or two to set up and run the integration analysis with the proposed demand-side program.

RESPONSE: The commission agrees with its Staff. MEEIA states: "The commission shall consider the total resource cost test "a" preferred cost-effectiveness test." MEEIA does not state the total resource cost test shall be "the" cost-effectiveness test or even (as stated in the formal comments of the stakeholder group) "the primary" cost-effectiveness test. So, clearly there is additional opportunity for the commission to choose a more comprehensive process to determine what demand-side resources constitute all cost-effective demand-side savings than simply using the total resource cost test. If the Commission stops with the results of the TRC, then demand-side analysis is given preferential treatment over supply-side analysis which is contrary to the MEEIA.

While "a" goal of MEEIA is to achieve all cost-effective demand-side savings, the stated fundamental objective of the proposed Chapter 22 rules is to provide the public with energy services that are safe, reliable and efficient, at just and reasonable rates, in a manner that serves the public interest. This objective further enhances the MEEIA, and is also consistent with sound public policy. This objective requires that the utility:

A. Consider and analyze demand-side resources and supply-side resources on an equivalent basis;

B. Use minimization of the present worth of long-run utility costs as the primary selection criterion in choosing the preferred resource plan; and

C. Explicitly identify and, where possible, quantitatively analyze any other considerations which are critical to meeting the fundamental objective of the resource planning process, but which may constrain or limit the minimization of the present worth of expected utility costs. ... These considerations shall include, but are not necessarily limited to, mitigation of risks associated with critical uncertain factors (such as future electricity loads, future economic conditions, future fuel and purchased power prices, and future legal mandated including environmental regulations). Finally, Chapter 22 risk analysis also considers the mitigation of rate increases associated with alternative resource plans.

The stakeholder group is suggesting that the total resource cost test is the only analysis needed to determine all cost-effective demand-side savings. The TRC may use as few as a single avoided cost amount for a year. Chapter 22 uses the total resource cost test to screen demand-side resources. Chapter 22 then requires further analysis of all resources that have passed screening analysis (both supply-side resources and demand-side resources) through integration analysis. The integration process required by Chapter 22 requires the utilities to look at all 8,760 hours of the year. The demand-side and supply-side resources that best meet the load requirements of all 8,760 hours each year are included in the preferred resource plan. The integration process is followed by risk analysis and finally strategy selection by the utility's decision makers. The programs that survive this rigorous screening should be the programs for which the utilities' request the Commission's approval and receive "non-traditional" rate making treatment. These programs are also the most likely to be the best use of the rate payers' money.

While this stakeholder group asserts that it is inappropriate that the judgment of utility decision makers be used for the determination of all cost-effective demand-side savings for its utility, ultimately, it is the utility decision makers who decide which alternative resource plan best meets the Chapter 22 objective for its utility. The utility decision makers (and not the total resource cost test) decide which DSM programs and demand-side programs investment mechanisms are proposed to the Commission. And these same utility decision makers will be accountable for the delivery and performance of their utility's Commission-approved DSM programs.

Finally, as the Staff clarifies, should the electric utility determine that it wants to propose demand-side programs or program plans which are not included in the electric utility's preferred resource plan, a completely new Chapter 22 analysis and new preferred resource plan are not necessary. The only requirement is that the programs and program plans be analyzed through the integration process required by 4 CSR 240-22.060.

The commission will make no changes to the language identified by these comments in the proposed rule or to any other language in the rule that would be related to the issue raised in these comments.

COMMENT # 13 – APPLICATIONS FOR APPROVAL OF MODIFICATIONS TO ELECTRIC UTILITY DEMAND-SIDE PROGRAMS

MEDA proposes two changes to the language in the first paragraph of 4 CSR 240-20.094(4), by changing the "demand-side program" to "demand-side plan" and revising the annual budget language to a three-year budget. These changes would allow flexibility in the timing of applications for modification of the plan, and reduce the number of applications. MEDA states the proposed rule allows very little flexibility as most changes within a program would trigger the requirement to file for Commission approval of that change. Changing the focus to the demand-side program plan would require Missouri utilities to seek approval when making major modifications to its demand-side plan. In other words, if a utility plans to significantly deviate from the program which it has filed with the Commission, then filing for a modification makes sense. Filing every time a utility needs to reallocate funds between already approved programs does not accomplish any purpose. The subsection, according to MEDA, should be corrected to read as follows:

> Applications for approval of modifications to electric utility demand-side programs. Pursuant to the provisions of this rule, 4 CSR 240-2.060, and section 393.1075, RSMo, an electric utility shall file an application with the commission for modification of demand-side programs by filing information and documentation required by 4 CSR 240-3.164(4) when there is a variance of twenty percent (20%) or more in the approved demand-side ~~program annual~~ plan three-year budget and/or any program design modification which is no longer covered by the approved tariff sheets for the program. . . .

RESPONSE AND EXPLANATION OF CHANGE: The commission agrees with MEDA and will adopt its suggested change.

COMMENT # 14 – PROVISIONS FOR CUSTOMER TO OPT-OUT OF PARTICIPATION IN UTILITY DEMAND-SIDE PROGRAMS

MDNR, NRDC, Sierra Club, Renew Missouri, GRELC are concerned with the current language in 4 CSR 240-20.094(6). According to these stakeholders, Section 393.1075.7, RSMo, allows three categories of large customers to opt out of utility offered programs. It allows customers in two categories, i.e., those with a demand over 5,000 kW at one or more accounts and those who operate an interstate pipeline pumping station, to opt out without any requirement that they capture all cost-effective energy efficiency potential in their operations. The proposed rule allows customers in the third category, those with a demand over 2,500 kW in aggregate from all their accounts, to opt out if they can demonstrate to staff that their internal programs will produce savings at least equal to those expected from utility provided programs. However, the rule does not specify the criteria by which staff is to evaluate the validity of the customer's projected savings; all it requires is a "demonstration" that a customer qualifies for the opt-out. 20.094(6)(C)3. These stakeholders believe the proposed rules can be improved by imposing as a condition of opt-out a requirement that those "opt-out" customers with demand over 2,500 kW in aggregate from all their accounts periodically demonstrate, subject to independent verification, that they have used and/or are using their own funds to install efficiency measures that are cost-effective to the same extent and according to the same avoided cost assumptions and cost-effectiveness tests as those used by their utility.

Walmart Stores East, LP, and Sam's East ("Walmart"), commented on the opt-out language and supports the current language. Walmart is opposed to any additional requirements because it believes the statute is clear in that it provides that the customer is the one that elects to notify the electric utility that it wants to opt out. Walmart does not believe there is any room to impose any requirements.

RESPONSE: The commission does not believe that MEEIA conveys it any authority to place the condition requiring periodically demonstrations and independent verification that customers who have opted out have used and/or are using their own funds to install efficiency measures that are cost-effective to the same extent and according to the same avoided cost assumptions and cost-effectiveness tests as those used by their utility. The commission will not adopt the suggestion from the environmental stakeholders to add such a condition.

COMMENT # 15 - REVOCATION

MDNR, NRDC, Sierra Club, Renew Missouri, GRELC have concerns about the language in 4 CSR 240-20.094(6)(H). These entities request that the language which states that customers "revoke an opt-out by providing written notice to the utility and commission fourteen (14) to sixteen (16) months in advance of the calendar year for which it will become eligible for the utility's demand-side program's costs and benefits" be changed to reduce this period to six (6) months. If they opt back in, and participate in a program, they should be required to remain in for the number of years over which the cost of that program is being recovered, or until the cost of their participation in that program has been recovered. The changes proposed by these stakeholders to 4 CSR 240-20.094(6)(H) may also require changes to 4 CSR 240-20.094(6)(F).

RESPONSE AND EXPLANATION OF CHANGE: There are two parts to this request. First is the recommendation to reduce the notification deadline for revoking an opt-out from participation in a demand-side program, and second is the recommendation to place conditions on entities opting back into a demand-side program. With regard to the first suggestion, the commission agrees to shorten this time period, but it will modify the language in 4 CSR 240-20.094(6)(H) by deleting "fourteen (14) to sixteen (16) months" and substituting "two (2) to four (4) months."

With this change the advanced notice in 4 CSR 240-20.094(6)(H) for any customer revocation notice will be made during the "same window of time" ("no earlier than September 1 and not later than October 30 to be effective for the following calendar year) as any customer notice for opt-out in 4 CSR 240-20.094(6)(F) and will more accurately accomplish the same objective as the proposed change to "six months". In this way the opt-out and revocation of opt-out will both be effective for the following calendar year.

With regard to the second suggestion, Section 393.1075(8) authorizes the commission to place conditions on entities desiring to opt back into a demand-side program. The commission agrees with these stakeholders and will adopt their suggested condition, thus, if a customer opts back in, and participates in a program, they will be required to remain in for the number of years over which the cost of that program is being recovered, or until the cost of their participation in that program has been recovered. The commission will added the following language to 4 CSR 240-20.094(6)(H) to implement this change:

Any customer revoking an opt-out to participate in a program will be required to remain in the program for the number of years over which the cost of that program is being recovered, or until the cost of their participation in that program has been recovered.

COMMENT # 16 – COLLABORATIVE GUIDELINES

MDNR, NRDC, Sierra Club, Renew Missouri, GRELC request that 4 CSR 240-20-094(8)(B) be completely replaced with the following language:

Statewide Collaboratives. Electric utilities and their stakeholders will form a statewide advisory collaborative:

(1) To receive and share information on new developments and programs;
(2) To develop a Missouri Technical Resource Manual (TRM);
(3) To explore joint programs where such programs could reduce program costs and increase savings;
(4) To provide a forum for national and regional experts to discuss developments in the energy efficiency, demand-side management, demand response, and renewable energy domains; and
(5) To discuss program results, including successes, challenges and mid-course corrections. Collaborative meetings will be led by an independent third-party selected by the commission.

This third party will

1. Be responsible for organizing, facilitating, and recording collaborative meetings.
2. Prepare meeting agendas based on input from collaborative participants. Agendas may propose time for both individual utility topics as well as topics of statewide interest and concern.
3. Schedule meetings bi-annually, and ensure that meetings:
    i. Are publicly announced and open to any interested party,
    ii. Include representatives from all interested groups and
    iii. Are structured to ensure that active participants have the opportunity to interact on necessary matters; and
4. Prepare minutes of each meeting, allowing all participants an opportunity to review and comment on the minutes.

The Statewide DSM Collaborative and the Technical Reference Manual (TRM) are described in 4 CSR 240-20-093 and 4 CSR 240-20-094. The TRM is defined in 4 CSR 240-20.093(1)(BB):

Statewide technical reference manual means a document that is used by electric utilities to assess energy savings and demand savings attributable to energy efficiency and demand response; and the role of the TRM in the Evaluation, Measurement and Validation (EM&V) of savings is described in 4 CSR 240-20.093(7)(E):

Electric utility's EM&V contractors shall use, if available, a commission approved statewide technical reference manual when performing EM&V work. This statewide process (the Statewide Collaborative) and common documentation (the TRM) are essential to developing a common perspective among Missouri utilities and stakeholders. These common activities will help to educate all parties about successful program designs and savings opportunities. Additionally, developing a TRM will provide needed information for assessing the outcomes of utility programs. The DSM portfolios of individual electric utilities feature many common programs. Each utility has a residential lighting program, a Home Performance with Energy Star program, a set of appliance rebate and maintenance programs, a set of commercial and industrial rebate programs, and a set of educational programs. Having a common forum to discuss the implementation of these common programs, to explore new program designs, and to investigate new technologies will help Missouri utilities to improve energy savings throughout the state. These entities request that the rule language in 4 CSR 240-20-094(8)(B) be changed to establish the procedures to require the creation of a statewide collaborative meeting and the establishment of a common TRM.

OPC supports the position offered by these stakeholders.

RESPONSE AND EXPLANATION OF CHANGE: The commission believes that at this early stage of implementing these proposed rules that it is important to maintain flexibility. The commission also sees significant practical and financial hurdles associated with attempting to utilize a third party administrator in association with the collaboratives. Consequently, the commission will not adopt the suggested replacement of the entire subsection on collaboratives.

Examining this issue, however, has led the commission to the conclusion that the collaborative should be mandatory and not discretionary. The commission will strike the words "are encouraged to" from 4 CSR 240-20-094(8)(A) and (B) and replace those words with the word "shall."

COMMENT # 17 – SPECIFIC LANGUAGE CHANGES

OPC believes that additional language should be added to various definitions in 4 CSR 240-20.094(1), and (3) to provide clarity and consistency with the statutory language in MEEIA.

** It should be noted that because OPC attempted to incorporate it's red-line filing from July 23, 2010 (prior to the official comment period), and because changes to the language of the proposed rule had been made after that date, but prior to the submission of the proposed rules for its publication in the Missouri Register, not all of the subsections of OPC's July 23, 2010 filing match the current proposed rule.

OPC proposes the following changes for 4 CSR 240-20.094(1):

(O) Evaluation, measurement and verification or EM&V means the performance of studies and activities intended to evaluate the process of <u>the utility's program delivery and oversight</u> and to estimate the energy and demand savings, cost effectiveness, and other effects from demand-side programs.

(P) Hard-to-reach customers means Residential customers with an annual household income at or below 200% of the federal poverty guidelines

(P) Interruptible or curtailable rate means a rate under which a customer receives a reduced charge in exchange for agreeing to allow the utility to ~~withdraw~~ interrupt or curtail some or all of the supply of electricity under certain specified conditions.

(Q) Load management means load control activities that result in a reduction in peak demand on an electric utility system or a shifting of energy usage from a peak to an off-peak period or from high-price periods to lower price periods.

(S) Total resource cost test or TRC means the test that compares the avoided utility costs (including probable environmental compliance costs) to the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions), plus utility costs to administer, deliver and evaluate each demand-side ~~program to quantify the net savings obtained by substituting the demand-side program for supply-side resources.~~ The present value of the program avoided utility benefits shall be calculated over the projected life of the measures installed under the program.

OPC proposes the following changes for 4 CSR 240-20.094(3)(A):

2. Include initiatives that are expected to achieve substantial program participation by hard to reach customers.

3. Reflect efforts undertaken by the utility to increase the cost effectiveness of, and/or level of participation in, its programs through coordinated or jointly-delivered programs with other electric and gas utilities.

~~2~~3. Have reliable evaluation, measurement and verification plans;

~~3~~4. Are estimated to be beneficial to all customers in the customer class in which the program is proposed, regardless of whether the program is utilized by all customers in that customer class; and

~~4~~5. Are included in the electric utility's preferred plan or have been analyzed through the integration process required by 4 CSR 240-22.060 to determine the impact of the demand-side programs and program plans on the net present value of revenue requirements of the electric utility.

OPC proposes the following changes for 4 CSR 240-20.094(3)(B):

1. If a program is targeted to low-income customers, the electric utility must also state how the electric utility will assess the expected and actual effect of the program on the utility's bad debt expenses and customer arrearages and disconnections.

RESPONSE: Perhaps OPC has not re-visited its comments from July, 23, 2010, but the current version of the proposed rule adopted language in 4 CSR 240-20.094(3)(B) that is identical to the OPC's proposed language. Finding there is no distinction between the current language and this proposed change, the commission will not amend that subsection. Further, the commission has addressed OPC's concern with regard to the definition of the Total Resource Cost test in its response to Comment # 5 and it need not repeat that response here.

With regard to the remaining changed proposed by OPC above, the commission notes that when OPC filed these proposed changes it stated in its filing: "Many of these changes are self-explanatory (e.g. to provide clarity or consistency with the language in MEEIA) and some are described in the comments below." The commission addressed the specific comments that OPC provided an explained for in other portions of this order, or in the orders of the interrelated MEEIA rules. With regard to these remaining suggestions, the commission notes that while it appreciates OPC's suggestions, offering them without providing an explanation or explaining how these changes would interact with and/or change the interrelated rules, by simply stating these changes are "self-explanatory" is unacceptable. It does not allow any other stakeholder the opportunity to address the specifics of the proposed changes and creates the potential for mischief.

Nevertheless, the commission has examined these proposed changes and does not believe they add any clarity to the current language. Finding there is no benefit to the proposed changes, the commission will not adopt them. The commission notes it is possible that the commission will amend this rule in the future. Indeed, 4 CSR 240-20.094(10) mandates a complete review of the effectiveness of this rule no later than four years after the effective date. During the review process the commission can revisit these proposed changes, and any others that OPC or any other entity would like to present and fully develop.

COMMENT # 18 – CROSS REFERENCE WITH COMMENT 12 IN INTER-RELATED RULE 4 CSR 240-20.093: REQUIREMENTS FOR SEMI-ANNUAL ADJUSTMENTS OF DSIM RATES

The MEDA stakeholders express concerns over the language in 4 CSR 240-20.093(4)(A)-(D). The language, according to MEDA, sets forth the requirements for semi-annual adjustments of DSIM and it should be modified to apply not only to the cost recovery component of the DSIM, but also to all components of the DSIM, i.e. cost recovery, lost margins or lost revenues and incentive. The MEDA stakeholders recommend that in order to comply with the intent of the MEEIA, in particular timely cost recovery to utilities, aligning utility financial incentives with helping customers use energy efficiently, and providing timely earnings opportunities associated with cost-effective energy efficiency -- adjustments of DSIM rates between general rate proceedings should apply to all components of the DSIM. These three components must be addressed in concert to provide a sustainable business model for utilities to pursue DSM programs and both benefit customers and satisfy shareholders.

RESPONSE AND EXPLANATION OF CHANGE: These proposed changes for section of 4 CSR 240-20.093, created a ripple effect with 4 CSR 240-20.094 that the commission must address in this proposed rule. The commission will not modify the language in 4 CSR 240-20.093(4) as proposed by MEDA to allow adjustments to the DSIM utility lost revenue requirement or to the DSIM utility incentive revenue requirement during the semi-annual adjustment to DSIM rates. The commission notes determination of the DSIM utility lost revenue requirement and the DSIM utility incentive revenue requirement are dependent upon measurement and verification performed by an EM&V contractor and documented in EM&V reports. Such EM&V reports will be performed in accordance with EM&V plan for each demand-side program and demand-side program plan required by 4 CSR 240-3.164(2)C)13 and will be likely be published no more frequently than annually and will not be available semiannually. However, the DSIM cost recovery revenue requirement is not dependent upon measurement and verification performed by an EM&V contractor and documented in EM&V reports but rather depends upon the contemporaneous accounting records of each electric utility.

In the process of reviewing this issue the commission noticed some internal inconsistencies and finds it is necessary to make changes to language contained in 4 CSR 240-20.093(1) and (2). Similarly, three definitions in 4 CSR 240-20.094(1) and Section (3) must be changed to maintain conformity throughout all four MEEIA rules. These changes should provide clarification to this issue. These changes include:

(1)(L) DSIM cost recovery revenue requirement means the revenue requirement approved by the commission in a utility's filing for demand-side program approval ~~proceeding~~ or a semi-annual DSIM rate adjustment case to provide the utility with cost recovery of demand-side program costs based on the approved cost recovery component of a DSIM;

(1)(M) DSIM utility incentive revenue requirement means the revenue requirement approved by the commission ~~in a utility's filing for demand-side program approval~~ ~~proceeding~~ to provide the utility with a portion of annual net shared benefits based on the approved utility incentive component of a DSIM ~~on the achieved performance level of approved demand-side programs demonstrated through energy and demand savings measured and documented through EM&V reports compared to energy and demand savings targets~~;

(1)(N) DSIM utility lost revenue requirement means ~~the component of~~ the ~~utility's~~ revenue requirement explicitly approved (if any) by the commission ~~in a utility's filing for demand-side program approval proceeding~~ to ~~address~~ provide the utility with recovery of lost revenue based on the approved utility lost revenue component of a DSIM;

(3) Applications for Approval of Electric Utility Demand-Side Programs or Program Plans. Pursuant to the provisions of this rule, 4 CSR 240-2.060, and section 393.1075, RSMo, an electric utility may file an application with the commission for approval of demand-side programs or program plans by filing information and documentation required by 4 CSR 240-3.164(2). Any existing demand-side program with tariff sheets in effect prior to the effective date of this rule shall be included in the initial application for approval of demand-side programs if the utility intends for unrecovered and/or new costs related to the existing demand-side program be included in the DSIM cost recovery revenue requirement, ~~DSIM utility lost revenue requirement~~, and/or if the utility intends to establish a utility lost revenue component of a DSIM or a ~~DSIM~~ utility incentive component of a DSIM ~~revenue requirement~~ for the existing demand-side program. The commission shall approve, approve with modification acceptable to the electric utility, or reject such applications for approval of demand-side program plans within one hundred twenty (120) days of the filing of an application under this section only after providing the opportunity for a hearing. In the case of a utility filing an application for approval of an individual demand-side program, the commission shall approve, approve with modification acceptable to the electric utility, or reject applications within sixty (60) days of the filing of an application under this section only after providing the opportunity for a hearing.

Title 4—DEPARTMENT OF ECONOMIC DEVELOPMENT
Division 240—Public Service Commission
Chapter 20—Electric Utilities

4 CSR 240-20.094 Demand-Side Programs

(1) As used in this rule, the following terms mean:

(C) Annual net shared benefits means the utility's avoided costs measured and documented through evaluation, measurement, and verification (EM&V) reports for approved demand-side programs less the sum of the programs' costs including design, administration, delivery, end-use measures, incentives, EM&V, utility market potential studies, and technical resource manual on an annual basis;

(D) Avoided cost or avoided utility cost means the cost savings obtained by substituting demand-side programs for existing and new supply-side resources. Avoided costs include avoided utility costs resulting from demand-side programs' energy savings and demand savings associated with generation, transmission, and distribution facilities including avoided probable environmental compliance costs. The utility shall use the same methodology used in its most recently-adopted preferred resource plan to calculate its avoided costs;

(L) DSIM cost recovery revenue requirement means the revenue requirement approved by the commission in a utility's filing for demand-side program approval or a semi-annual DSIM rate adjustment case to provide the utility with cost recovery of demand-side program costs based on the approved cost recovery component of a DSIM;

(M) DSIM utility incentive revenue requirement means the revenue requirement approved by the commission to provide the utility with a portion of annual net shared benefits based on the approved utility incentive component of a DSIM;

(N) DSIM utility lost revenue requirement means the revenue requirement explicitly approved (if any) by the commission to provide the utility with recovery of lost revenue based on the approved utility lost revenue component of a DSIM;

(S) "Filing for demand-side program approval means a utility's filing for approval, modification or discontinuance of demand-side program(s) which may also include a simultaneous request for the establishment, modification or discontinuance of a DSIM."

(T) Interruptible or curtailable rate means a rate under which a customer receives a reduced charge in exchange for agreeing to allow the utility to withdraw the supply of electricity under certain specified conditions;

(U) Lost revenue means the net reduction in utility retail revenue, taking into account all changes in costs and all changes in any revenues relevant to the Missouri jurisdictional revenue requirement, that occurs when utility demand-side programs approved by the commission in accordance with 4 CSR 240-20.094 cause a drop in net system retail kWh delivered to jurisdictional customers below the level used to set the electricity rates. Lost revenues are only those net revenues lost due to energy and demand savings from utility demand-side programs approved by the commission in accordance with 4 CSR 240-20.094 Demand-Side Programs and measured and verified through EM&V;

(V) Preferred resource plan means the utility's resource plan that is contained in the resource acquisition strategy most recently adopted by the utility's decision-makers in accordance with 4 CSR 240-22;

(W) Probable environmental compliance cost means the expected cost to the utility of complying with new or additional environmental legal mandates, taxes, or other requirements that, in the judgment of the utility's decision-makers, may be imposed at some point within the planning horizon which would result in environmental compliance costs that could have a significant impact on utility rates;

(X) Staff means all personnel employed by the commission, whether on a permanent or contract basis, except: commissioners, commissioner support staff including technical advisory staff, personnel in the secretary's office, and personnel in the general council's office including personnel in the adjudication department. Employees in the staff's counsel's office are members of the commission's staff;

(Y) Total resource cost test, or TRC, means the test of the cost-effectiveness of demand-side programs that compares the avoided utility costs to the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions), plus utility costs to administer, deliver, and evaluate each demand-side program; and

(Z) Utility incentive component of a DSIM means the methodology approved by the commission in a utility's demand-side program approval proceeding to allow the utility to receive a portion of annual net shared benefits achieved and documented through EM&V reports.

(2) Guideline to Review Progress Toward an Expectation that the Electric Utility's Demand-Side Programs Can Achieve a Goal of All Cost-Effective Demand-Side Savings. The goals established in this section are not mandatory and no penalty or adverse consequence will accrue to a utility that is unable to achieve the listed annual energy and demand savings goals.

(3) Applications for Approval of Electric Utility Demand-Side Programs or Program Plans. Pursuant to the provisions of this rule, 4 CSR 240-2.060, and section 393.1075, RSMo, an electric utility may file an application with the commission for approval of demand-side programs or program plans by filing information and documentation required by 4 CSR 240-3.164(2). Any existing demand-side program with tariff sheets in effect prior to the effective date of this rule shall be included in the initial application for approval of demand-side programs if the utility intends for unrecovered and/or new costs related to the existing demand-side program be included in the DSIM cost recovery revenue requirement, and/or if the utility intends to establish a utility lost revenue component of a DSIM or a utility incentive component of a DSIM for the existing demand-side program. The commission shall approve, approve with modification acceptable to the electric utility, or reject such applications for approval of demand-side program plans within one hundred twenty (120) days of the filing of an application under this section only after providing the opportunity for a hearing. In the case of a utility filing an application for approval of an individual demand-side program, the commission shall approve, approve with

modification acceptable to the electric utility, or reject applications within sixty (60) days of the filing of an application under this section only after providing the opportunity for a hearing.

(4) Applications for Approval of Modifications to Electric Utility Demand-Side Programs. Pursuant to the provisions of this rule, 4 CSR 240-2.060, and section 393.1075, RSMo, an electric utility shall file an application with the commission for modification of demand-side programs by filing information and documentation required by 4 CSR 240-3.164(4) when there is a variance of twenty percent (20%) or more in the approved demand-side plan three-year budget and/or any program design modification which is no longer covered by the approved tariff sheets for the program. The commission shall approve, approve with modification acceptable to the electric utility, or reject such applications for approval of modification of demand-side programs within thirty (30) days of the filing of an application under this section, subject to the same guidelines as established in subsections (3)(A) through (C), only after providing the opportunity for a hearing.

(6) Provisions for Customers to Opt-Out of Participation in Utility Demand-Side Programs.

(H) Revocation. A customer may revoke an opt-out by providing written notice to the utility and commission two (2) to four (4) months in advance of the calendar year for which it will become eligible for the utility's demand-side program's costs and benefits. Any customer revoking an opt-out to participate in a program will be required to remain in the program for the number of years over which the cost of that program is being recovered, or until the cost of their participation in that program has been recovered.

(8) Collaborative Guidelines.

(A) Utility-Specific Collaboratives. Each electric utility and its stakeholders shall form a utility-specific advisory collaborative for input on the design, implementation, and review of demand-side programs as well as input on the preparation of market potential studies. This collaborative process may take place simultaneously with the collaborative process related to demand-side programs for 4 CSR 240-22. Collaborative meetings are encouraged to occur at least once each calendar quarter.

(B) State-Wide Collaboratives. Electric utilities and their stakeholders shall form a state-wide advisory collaborative to: 1) address the creation of a technical resource manual that includes values for deemed savings, 2) provide the opportunity for the sharing, among utilities and other stakeholders, of lessons learned from demand-side program planning and implementation, and 3) create a forum for discussing state-wide policy issues. Collaborative meetings are encouraged to occur at least once each calendar year. Staff shall provide notice of the statewide collaborative meetings and interested persons may attend such meetings.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Chairman's Request for A Status Report Regarding Energy Efficiency Advisory Groups and Collaboratives	)))	**File No. AO-2011-0035**
In the Matter of the Consideration and Implementation of Section 393.1075, RSMo., The Missouri Energy Efficiency Investment Act	))))	**File No. EX-2010-0368**

CHAIRMAN CLAYTON'S CONCURRENCE TO FINAL ORDER OF RULEMAKING AND RESPONSE TO STAFF'S REPORT

Issue Date: February 9, 2011

This Commissioner files this opinion in support of the Final Order of Rulemaking in File No. EX-2010-0368, regulations formulating future efforts in energy efficiency investments for Missouri investor-owned utilities. Additionally, this opinion sets out this Commissioner's response to the Staff Report on energy efficiency programs, filed in Case No. AO-2011-0035. These two cases demonstrate the new commitment to energy efficiency in Missouri in empowering utility customers to take control of their energy bills.

In response to my request, the Staff of the Commission filed a report on September 15, 2010, describing the work of each energy efficiency advisory group and collaborative currently addressing the energy efficiency issues facing Missouri's investor-owned electric and natural gas utilities. The report is an impressive compilation of material summarizing the changes in Missouri's efforts at improving the efficient delivery and use of energy. As our nation faces an uncertain future with regard to energy-related priorities, the compilation of material demonstrates the Commission's new commitment to assisting customers and utilities in better managing our energy usage through efficiency programs.

The report highlights that in the past several years, Missouri utilities have gone from a few efficiency programs inconsistently scattered among varying sectors to a comprehensive offering of programs with relatively consistent goals among all utilities. Collaboratives or stakeholder groups have been established for each utility to collect input and formulate policy involving diverse groups, associations and agencies with many people effectively engaged. Program offerings are considered, funded and implemented through the collaboratives, with joint recommendations made to the Commission for approval or rejection in a rate case. Procedures are now in place for resolution of disputes among parties and more information is being distributed to more utility customers than ever before with a wide array of opportunities to reduce energy bills.

The concept of energy efficiency is being embraced as never before. Utilities are now recognizing the benefits of efficient use through reduced demand and energy charges and with less urgency in identifying new sources of electric generation or natural gas acquisition. With increased efficiency of energy use, customers are less vulnerable to natural gas price volatility. Utilities are able to delay or avoid costly new energy sources. Demand Response programs are in place in some territories in attempts to avoid the use of costly gas "peaker plants" in times of high demand, which demonstrate that utilities and customers can benefit from reducing power generation costs. Efficiency programs, in general, are smoothing increases in overall demand with more manageable growth, while avoiding the difficulties of securing new, costly baseload generation.

Customers have much to gain from efficient use of energy. While customers benefit from lower utility costs, customers also receive the direct benefit education and training in learning how energy is used, how it is priced and how they can find ways to reduce consumption, thereby , reducing their monthly energy bills. Customers must have greater options through utility programs in evaluating appliance purchases, understanding heating and cooling needs, learning about new technologies, and learning that one's quality of life does not have to decrease when energy is used more efficiently. To customers, effective energy efficiency programs translate into empowerment to take control of their energy bills. Rebates, incentives and education provide customers with the necessary tools to change behavior and change how energy decisions are made.

The Commission has recognized that these new programs require adequate funding to be effective. In 2000, total funding for efficiency programs focused primarily on weatherization in the amount of $875,000, involving a couple of utilities. In 2010, funding levels have increased to $53 million, including all 8 utilities. The Commission has determined that natural gas utilities should strive for the target of EE funding at a minimum of .5% of their gross revenues, and all large gas utilities are moving toward this policy target. Electric utilities are taking similar steps at developing and delivering a comprehensive offering of efficiency programs with sufficient funding levels.

Lastly, as Missouri ramps up its efficiency programs, its investments and its increase in knowledge and action for customers, this Commission and future Commissions must be prepared to address an evolving utility industry. If load growth is curtailed, there will be pressure to reevaluate how rates are set. Utilities will push for equal or greater returns on efficiency investments and new models of incentives for utility performance in meeting Commission goals and priorities. Utilities will demand fair treatment if downward pressure is applied to their efforts at increasing sales for greater revenue. On the other hand, consumers will demand that the Commission apply close supervision to new programs, carefully scrutinize new rate making requests and cautiously evaluate any modification to the traditional rate of return regulatory compact. This and future Commissions will be faced with balancing these potentially competing positions to ensure that programs are cost-effective, deliver benefits to both customers and utilities, and do not inequitably shift risk or cost. These are complicated challenges in a new world of energy delivery.

The Commission is prepared to tackle these issues and has taken additional steps to gather information and set policy. First, the Commission continues its statewide energy efficiency study with a partnering agency, the Missouri Energy Center. It is this Commissioner's hope that realistic, achievable goals can be identified to provide greater assistance to those working on Missouri's energy future. Secondly, the Commission has concluded the formal rulemaking process with regulations stemming from Senate Bill 376, the Missouri Energy Efficiency Act. Through these rules, the Commission addresses a number of significant policy questions to provide clarity and certainty for current and future efficiency programs. The Commission has developed the rules with an eye towards flexibility and the understanding that incentive mechanisms will require careful planning and design. The Commission will need several "attempts" at determining the large-scale benefits and costs upon all stakeholders. Lessons learned from those efforts will provide future commissions with the knowledge to develop programs effectively. The rules certainly contemplate a changing world where the regulator may no longer demand greater sales of energy, but rather strive for decreased usage. How does a utility reduce its sales but maintain profitability? The rules are designed to consider this conundrum.

In conclusion, this Commissioner commends and thanks the staff of the Commission for its efforts in working through challenging and potentially controversial issues. Most Missourians are unaware of the work of the Public Service Commission and even fewer know the dedication, the expertise and the significant work ethic of the PSC staff. This report illustrates the giant steps taken in recent years and the future work that lies ahead. It is my hope and request that a similar report be prepared annually, in a format for easy consumption, so that the public and Commissioners may understand what we are doing on critically important issues and how those issues evolve in the future.

Therefore, it is my request that the Staff prepares an annual update to its report, in a format acceptable to Staff, every September 15th, and makes that update available to the Commission and the public.

For the foregoing reasons, this Commissioner concurs.

Respectfully submitted,

Robert M. Clayton III
Chairman

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Consideration and Implementation of Section 393.1075, the Missouri Energy Efficiency Investment Act	)))	Case No. EX-2010-0368

DISSENTING OPINION OF COMMISSIONER ROBERT S. KENNEY

I write to dissent from the majority's Final Orders of Rulemaking regarding the Missouri Energy Efficiency Investment Act.[1] I specifically dissent as it relates to those Rules allowing utilities to recover lost revenue. I dissent because the Missouri Energy Efficiency Investment Act (the "MEEIA" or the "Act"), the statute under which the Commission has authority to promulgate these Rules, does not authorize recovery of lost revenue; I dissent because authorizing recovery of lost revenues does nothing to remove the disincentive it is ostensibly designed to remove; and I dissent because authorizing recovery of lost revenues does not serve the interests of Missouri citizens.

I believe in energy efficiency as a least-cost way of reducing carbon emissions. Along with greater deployment of renewable resources, nuclear energy, and new technologies such as carbon capture and sequestration, energy efficiency measures are a certain and cost-effective way of reducing carbon emissions. Equally as important, energy efficiency measures give utility customers an opportunity to realize savings in their bills.

The MEEIA is the product of Senate Bill No. 376, which was first read February 16, 2009. As with most pieces of legislation, SB 376 as introduced differed from the Senate Substitute for Senate Committee Substitute for SB 376, which was the Truly

[1] 4 CSR 240-3.163; 4 CSR 240-3.164; 4 CSR 240-20.093; and 4 CSR 240-20.094 (collectively the "Rules").

Agreed To and Finally Passed bill as signed by Governor Nixon. I will discuss the relevance of this fact later. Governor Nixon signed SB 376 in July 2009. It is codified at Section 393.1075 of the Missouri Revised Statutes.

The MEEIA is a laudable piece of legislation. And the rules we have drafted in support of the MEEIA represent the hard work of our staff and numerous stakeholders. They are to be commended for their efforts. But the issue of lost revenue recovery is of such significance that including provisions allowing for the recovery of lost revenues damages the rules as a whole.

1. The MEEIA does not authorize recovery of lost revenue

The MEEIA sets forth the state's policy "to value demand side investment equal to traditional investment in supply and delivery infrastructure and allow recovery of all reasonable and prudent *costs* of delivering cost-effective demand-side programs." Mo. Rev. Stat. § 393.1075.3 (2010) (emphasis supplied). The MEEIA further provides that "the [C]ommission may develop *cost* recovery mechanisms to further encourage investments in demand side programs[.]" Mo. Rev. Stat. § 393.1075.5 (2010) (emphasis supplied).

The Commission is instructed to support the state's policy by providing timely cost recovery for utilities; by ensuring that utility financial incentives are aligned with helping customers use energy more efficiently and in a manner that *sustains or enhances utility customers' incentives* to use energy more efficiently; and by providing timely earnings opportunities associated with cost effective measurable and verifiable efficiency savings. Mo. Rev. Stat. § 393.1075.3 (1) – (3) (2010).

There is no language in the language I have cited or anywhere else in the statute that authorizes the recovery of lost revenue. Lost revenue is neither a *cost* of providing service nor a *cost* of providing energy efficiency programs.

The absence of any such language is telling. What is also telling is that the introduced version of SB 376 included language allowing for "recovery of lost sales attributable to approved energy efficiency programs" and "allowing the utility a fixed investment recovery mechanism to recover lost margins[.]" See Senate Bill No. 376, First Regular Session, 95th General Assembly, Read First Time February 16, 2009.

In the Truly Agreed To and Finally Passed version of the bill, signed by the Governor and codified at Section 393.1075, this language is conspicuously absent. While this absence is not dispositive of the General Assembly's intent, it is instructive. Had the General Assembly intended to authorize recovery of lost revenues, it certainly could have kept the language that appears in the introduced version of SB 376. In certain circumstances, such as this one, "omissions should be understood as exclusions." See, Angoff v. M and M Mgmt. Corp., 897 S.W.2d 649, 655 (Mo. Ct. App. 1995)

2. Allowing for recovery of lost revenue does not solve the problem

Encouraging energy efficiency, on the one hand, requires the utility to act counter to its financial interests. So, some form of lost revenue recovery mechanism is necessary, proponents assert, in order to remove this disincentive. But allowing for recovery of lost revenues does nothing to remove the incentive to increase revenues by increasing sales.

The lost revenue recovery mechanism is supposed to ameliorate the effects of any lost revenues specifically tied to measured and verified energy efficiency programs. The problem, however, is that the evaluation, measurement, and verification program will likely lead to increased contention as parties litigate the accuracy of the evaluation, measurement, and verification program. Moreover, every indication is that measuring and verifying lost revenues associated with specific energy efficiency programs is a highly imprecise undertaking. In addition to leading to more contentious rate cases, this imprecision allows opportunity for mischief in measuring and verifying the savings associated with a particular program. This is particularly true where, as is the case with the Rules, the utility is charged with evaluating, measuring, and verifying its own program.

Only eight states currently use some form of lost revenue recovery mechanism.[2] More states are looking to some form of revenue decoupling as a preferred method of addressing the disincentives associated with promoting energy efficiency. I do not, at this time, express an opinion about the desirability of decoupling. I only note that it provides a more certain means of removing the so-called "throughput incentive," that is the incentive to increase revenues by increasing sales. Additionally, performance incentives are another effective alternative for addressing the disincentives associated with promoting energy efficiency.

Lost revenue recovery mechanisms are also difficult to administer as the ability to properly implement such mechanisms depends to a significant degree on robust evaluation, measurement, and verification. And since any recovered lost revenues are

---

[2] Colorado, Kentucky, Montana, North Carolina, Ohio, Oklahoma, South Carolina, and Wyoming. Utah is considering a lost revenue recovery mechanism. As of this writing, the status of that mechanism is uncertain. See The Edison Foundation's Institute for Electric Efficiency, "State Electric Efficiency Regulatory Frameworks," July 2010, accessed at http://www.electric-efficiency.com/issueBriefs/IEE_StateRegulatoryFrame_0710.pdf, on February 7, 2011.

only those directly attributable to the energy efficiency program, the utility continues to have the incentive to increase revenues through increased sales.

In addition to the difficulty associated with administering an effective evaluation, measurement, and verification program, the use of the lost revenue recovery mechanism gives rise to many other questions. How are revenues attributable to energy efficiency programs distinguished from decreased sales attributable to any other factor? How are potential off-system sales taken into account that are realized as a result of any energy efficiency programs? Will customers reap the benefits of increased energy efficiency and decreased consumption in the way of lower bills if the "lost revenues" are ultimately recovered? Will customers' incentives to use energy more efficiently be sustained or enhanced, as instructed by the MEEIA? There are too many unanswered questions to leave one comfortable that allowing for recovery of lost revenues will advance the overarching goals of promoting energy efficiency or inure any great benefits to ratepayers.

3. Conclusion

Energy efficiency measures are to be encouraged and implemented to the greatest degree possible. Energy efficiency is a proven, cost-effective means of addressing many problems: global climate change caused by green house gas emissions; air quality issues; consumption and depletion of finite fossil fuel resources; and energy independence and security.

The policy of the state is to value demand side investments equal to other investments. Utilities' financial incentives are to be aligned with helping customers use energy more efficiently and in a manner that sustains and enhances their incentives to use energy more efficiently. The MEEIA makes these pronouncements and charges the commission with drafting rules in support of these worthy goals. The MEEIA gives the commission latitude in promulgating rules supportive of its goals. But the MEEIA does not authorize recovery of lost revenues.

Moreover, recovery of lost revenues does not address the problem that it sets out to resolve. While it provides revenue stability for the utility, it does not remove the incentive to promote increased sales. Finally, it is hard to see how allowing for recovery of lost revenues supports or enhances the customers' incentives to use energy more efficiently.

I wholeheartedly and enthusiastically support the overarching principles of the MEEIA. And I recognize the need to align utilities' financial incentives with helping customers decrease consumption of their product. But I do not believe that allowing for recovery of lost revenues achieves this alignment.

For all of the foregoing reasons I dissent.

Respectfully submitted,

Robert S. Kenney
Commissioner

Dated this 9th day of February 2011,
at Jefferson City, Missouri

FIRST REGULAR SESSION

SENATE BILL NO. 376

95TH GENERAL ASSEMBLY

INTRODUCED BY SENATORS LAGER AND CALLAHAN.

Read 1st time February 16, 2009, and ordered printed.

TERRY L. SPIELER, Secretary.

1744S.02I

AN ACT

To amend chapter 393, RSMo, by adding thereto one new section relating to energy efficiency investments by electric and gas corporations.

Be it enacted by the General Assembly of the State of Missouri, as follows:

Section A. Chapter 393, RSMo, is amended by adding thereto one new section, to be known as section 393.1124, to read as follows:

393.1124. 1. This section shall be known as the "Missouri Residential and Small Business Energy Efficiency Investment Act".

2. The public service commission shall permit electric and gas corporations to implement commission-approved energy efficiency programs proposed pursuant to this section. Such programs shall be beneficial to all customers in the customer class in which the program is proposed, regardless of whether the program is utilized by all customers.

3. The commission shall develop cost recovery mechanisms that value energy efficiency investments equal to or better than traditional supply side investments. Such mechanisms shall include the capitalization of investments in and expenditures for energy efficiency programs and a recovery of lost sales attributable to approved energy efficiency programs. The commission may also develop cost recovery mechanisms to further encourage investments in energy efficiency including, in combination and without limitation: an incentive rate of return higher than the rate of return on other investments, accelerated depreciation on energy efficiency investments, allowing the utility to retain a portion of the net benefits of an energy efficiency program for its shareholders, allowing the utility a fixed investment recovery mechanism to recover lost margins and a cost adjustment clause for

collection of costs associated with energy efficiency programs.

4. The commission may reduce or exempt allocation of energy efficiency expenditures to low income classes, as defined in an appropriate rate proceeding, as a subclass of residential service. No customer in any rate class shall pay more than five thousand dollars a month to support programs authorized under this section. Notwithstanding any other statute or commission rules, this section explicitly provides the commission authority to approve low income tariffs.

5. The commission shall provide oversight and may adopt rules and procedures and approve corporation-specific settlements and tariff provisions, as necessary, to ensure that electric and gas corporations can achieve the goals of this section. Any rule or portion of a rule, as that term is defined in section 536.010, RSMo, that is created under the authority delegated in this section shall become effective only if it complies with and is subject to all of the provisions of chapter 536, RSMo, and, if applicable, section 536.028, RSMo. This section and chapter 536, RSMo, are nonseverable and if any of the powers vested with the general assembly pursuant to chapter 536, RSMo, to review, to delay the effective date, or to disapprove and annul a rule are subsequently held unconstitutional, then the grant of rulemaking authority and any rule proposed or adopted after August 28, 2009, shall be invalid and void.

6. Each electric and gas corporation shall submit an annual report to the commission describing the energy efficiency programs implemented by the utility in the previous year. The report shall document program expenditures, including incentive payments, peak demand and energy savings impacts and the techniques used to estimate those impacts, avoided costs and the techniques used to estimate those costs, the estimated cost-effectiveness of the energy efficiency programs, and the net economic benefits of the energy efficiency programs.

✓