MEMORANDUM

TO: Stephen C. Reed, Secretary

DATE: February 9, 2011

RE: Authorization to File Order of Rulemaking with the Office of Secretary of State

FILE NO: EX-2010-0368

The undersigned Commissioners hereby authorize the Secretary of the Missouri Public Service Commission to file the following Order of Rulemaking with the Office of the Secretary of State, to wit:

Proposed Rule 4 CSR 240-20.093 – Electric Utilities

Robert M. Clayton III

Robert M. Clayton III, Chairman

Jeffrey M. Davis

Jeff Davis, Commissioner

Terry M. Jarrett

Terry M. Jarrett, Commissioner

KDG

Kevin D. Gunn, Commissioner

Robert S. Kenney . ND

Robert S. Kenney

Robin Carnahan
Secretary of State
Administrative Rules Division

RULE TRANSMITTAL

Administrative Rules Stamp

Rule Number 4 CSR 240-20.093

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
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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)(F), (1)(I), (1)(J), (1)(N), (1)(P), (1)(Q), (1)(R), (1)(T), (1)(Y), (1)(Z), (1)(BB), (1)(DD), (1)(EE), (2)(B), (2)(E), (2)(F), (2)(G)2, (2)(G)3, (2)(G)4, (2)(G)5, (2)(H)1, (2)(H)2, (2)(J), (3)(B), (4), (4)(B), (5), (7)(E) and (10)(B).
Sections (1)(X), (1)(AA), (1)(CC), and (1)(GG) have been relettered.
Sections (1)(W), (1)(FF), (2)(G)1, and (2)(H)3 have been added.

Small Business Regulatory Fairness Board (DED) Stamp

JCAR Stamp

JOINT COMMITTEE ON

FEB 09 2011

ADMINISTRATIVE RULES

Missouri Public Service Commission

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

Dear Secretary Carnahan:

Re: 4 CSR 240-20.093 Demand-Side Programs Investment Mechanisms

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
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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 240-20.093 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 1647). 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 16 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 240-20.094. 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 240-20.093 may be interrelated with these other proposed rules and the interplay between these proposed rules may need to be addressed in the context

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[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, this rule specifically addresses Demand-Side Program Investment Mechanisms. 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 240-20.093 - Purpose; (1)(I); (1)(M); (1)(N); (1)(P); (1)(Q); (1)(R); (1)(DD); 2; (2)(B); (2)(F); (2)(G); (2)(G)(1); (2)(G)(2); (2)(H); (2)(I); (3)(B); (3)(D); (4); (4)(A)-(D); (5); (5)(A); (6); (10); (10A); (10)(B); (10)(B)(1); (10)(B)(2).

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 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 240-20.093(1)(M); (1)(P); (1)(R); (1)(V); (1)(X); (2)(E); (2)(G) 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 240-3.164; 4 CSR 240-20.093 and 4 CSR 240-20.094, 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 240-2-.093(1)(X) 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 240-20.093(1)(R) 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 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.

Staff's proposed change would apply to definition section 4 CSR 240-20.093(1)(Y) 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 240-20.094(1)(U).

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 - Lost Revenue Adjustment Mechanism

The Staff of the Missouri Public Service Commission believes the language in 4 CSR 240-20.093(2)(G) is unclear and that if the commission is going to allow the recovery of lost revenues that the language needs to be clarified as follows:

(G) Any utility lost revenue component of DSIM shall be based on energy or 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.

1. A utility cannot recover revenues lost due to utility-demand side programs unless it does not recover the fixed cost as set in the last general rate case, i.e. actual annual billed system kWh is less than the system kWh used to calculate rates to recover revenues as ordered by the Commission in the utility's last general rate case.

2. The commission shall order any DSIM utility lost revenue requirement simultaneously with the programs approved in accordance with 4 CSR 240-20.094.

3. In a utility's demand-side program approval proceeding in which lost revenues are considered there is no requirement for any implicit or explicit lost revenue recovery or for a particular form of lost revenue component.

4. The commission may address lost revenues solely or in part, directly or indirectly, with a performance incentive mechanism through a utility incentive component of DSIM.

5. Any explicit lost revenue component of DSIM shall be implemented on a retrospective basis and all energy and demand savings for claimed lost revenues must be measured and verified through EM&V prior to recovery.

These revisions, according to Staff, clarify that lost revenues are only the result of changes in revenues that occur when Commission-approved demand-side programs cause a drop in net system retail kWh below the level of system retail kWh used to set the electricity rates in the electric utility's last general rate proceeding. In other words, a utility cannot recover revenues lost due to utility demand-side programs unless it does not recover the fixed costs set in the last general rate case. Moreover, incorporating the revisions will prevent a utility from "double dipping" by claiming lost revenues due to demand-side programs while continuing to build load. Finally, utilities would not be able to earn more than authorized if they raise sales between rate cases because, with the recommended revisions, if overall sales exceed the system retail kWh set in the last rate case, the utility would be unable to recover any lost revenues.

On the other hand, the MEDA stakeholders believe that 4 CSR 240-20.093(G)(2), (3) and (4), (see above) do not provide for full and timely recovery of revenues lost due to the impact of its energy efficiency programs, and thus is not in compliance with the Act. Lost revenues should be recovered on a one-to-one basis and should not be subject to meeting targets. It is inconsistent for the Commission to approve a three-year plan with a budget, targets, cost recovery and incentives, but then only allow the lost revenue component to be retrospective.

RESPONSE AND EXPLANATION OF CHANGE: As noted in the final orders of rulemaking for the interrelated rules, and in Comment # 3 above, 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 is modifying 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.

The commission now adopts Staff's clarifying language for 4 CSR 240-20.093(2)(G) for those same reasons.

COMMENT # 5 – 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:

<u>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.</u>

COMMENT # 6 – THE DEMAND-SIDE INVESTMENT MECHANISM

MDNR, NRDC, Sierra Club, Renew Missouri, GRELC recommend that 20.093(1)(M)4 be changed so that it explicitly invites utilities to file a DSIM that also includes a mechanism that would, "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." This mirrors the statutory language in § 393.1075.3(2), and will allow utilities to make the case for a DSIM that more fully meets the objective of the statute.

According to these stakeholders, Utility revenues rise when sales rise, and the converse is equally true — declining sales mean declining revenues. Thus, Missouri utilities can earn more than their authorized fixed costs revenue requirement if sales are higher than was projected during a rate case. This "throughput incentive" amounts to a strong disincentive for utilities to invest in energy efficiency or to support energy saving policies and measures outside their control, and the magnitude of the disincentive is substantial. The statutory directive to the commission to align utility financial incentives such that utilities are encouraged to support energy efficiency investments that save customers money is rendered meaningless if this powerful disincentive is not addressed in a meaningful and timely manner in this rulemaking.

The current draft offers the utilities an opportunity to file a mechanism by which it can recover "lost revenues," which it defines as follows: "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 occur when utility demand-side programs approved by the commission in accordance with ... cause a drop in net retail kilowatt hours 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 .... and measured and verified through EM&V." 4 CSR 240-3.163(1)(P). However, under such a mechanism, utilities would continue to see higher levels of revenue recovery with higher sales. Therefore 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.

MDNR, NRDC, Sierra Club, Renew Missouri, GRELC believe that under the mechanism provided for in the proposed rules, utility management would face this conflict at the prospect of supporting state building codes for energy-efficient construction, federal appliance standards that have successfully transformed the market for products ranging from refrigerators and televisions to air conditioners and lighting, or any action outside its own programs for advancing the use of increasingly efficient technologies. Such a mechanism would ultimately fail to align the utilities' financial incentives with the goals of the statute to capture all cost-effective energy efficiency for the benefit of ratepayers.

RESPONSE: As drafted, the proposed rule and the inter-related MEEIA rules, provide for timely cost recovery and timely earnings opportunities. And, as 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. The rule promotes the needed flexibility that ensures that the utility financial incentives are aligned with helping customers use energy more efficiently. The commission believes the concerns raised in this comment are unfounded and will not change the current language of the proposed rule.

COMMENT # 7 - DEFINITION OF PROBABLE ENVIRONMENTAL COSTS:

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. A single-Issue workshop docket could resolve the matter expeditiously. 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 <u>(including probable environmental compliance costs)</u> 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.~~ <u>The present value of the program avoided utility benefits shall be calculated over the projected life of the measures installed under the program</u>.

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 15 to this proposed rule and Comment # 17 to proposed rule 4 CSR 240-20.094. 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 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;

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. ~~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 (14) 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 # 8 – DEFINITION OF STAFF:

Staff believes that the word 'Staff" in 4 CSR 240-20.093(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)(Q), 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 # 9 – LANGUAGE ALLOWING PROPOSALS OF ALTERNATIVE DSIMS

The MEDA stakeholders are concerned about the language in 4 CSR 240-20.093(2)(B) that states: "Any party to the application for demand-side program approval proceeding may support or oppose the establishment, continuation, or modification of a DSIM and/or may propose an alternative DSIM for the commission's consideration including, but not limited to, modifications to any electric utility's proposed DSIM."

These stakeholders point to Section 393.1075.4, which according to them underscores the voluntary nature of the Act and the permissive language for electric utilities offering such programs when stating: "The commission shall permit electric corporations to implement commission-approved demand-side programs proposed pursuant to this section with a goal of achieving all cost-effective demand side savings." The Commission is an agency of limited jurisdiction and authority, and the lawfulness of its actions depends upon whether or not it has statutory authority to act.

According to these stakeholders, the current language can be used to compel a utility to accept a proposed alternative or modified DSIM with which it does not agree in contradiction to the permissive language in Section 393.1075.4. MEDA recommends language that would allow the electric utility to have the final say on whether any modification or "alternative DSIM" is acceptable.

RESPONSE AND EXPLANATION OF CHANGE: The commission agrees that this section requires clarification. It was not the intent of the rule to allow other entities to impose a DSIM or modifications to a DSIM to which the commission or the utility did not agree. The commission may approve an alternative or modified DSIM, but the utility will have the final decision as to whether to accept an alternative or modified DSIM. The commission will add the following sentence to this section:

<u>Both, the utility and the commission retain the authority to approve, accept or reject any proposed establishment, continuation, or modification of a DSIM or any proposed alternative DSIM.</u>

COMMENT # 10 – COST RECOVERY MECHANISM MODIFICATION

The MEDA stakeholders express concerns about the language in 4 CSR 240-093(2)(E). According to MEDA, the criteria placed in the proposed rule for the commission to consider whether to establish/modify/continue the cost recovery mechanism for DSM programs are not in the statute. MEEIA, Section 393.1075.3, states the Commission shall provide timely cost recovery so any other criterion exceeds the statutory authority.

MEDA believes the following language should be eliminated from this subsection: "the expected magnitude of the impact to the utility's approved demand-side programs on the utility's costs, revenue, and earning, the ability of the utility to manage all aspects of the approved demand-side programs." The remaining language would read" In determining to approve, modify, or continue a DSIM, the commission shall consider, but is not limited to only considering, the ability to measure and verify the approved program's impacts." This change places the focus more on the ability to measure and verify the approved program's impacts.

RESPONSE AND EXPLANATION OF CHANGE: The commission recognizes MEDA's concerns but it also does not wish to preclude consideration of any criteria that is relevant to its determination. Consequently, the commission change the mandatory language in this subsection to make it permissive as follows:

E) In determining to approve, modify, or continue a DSIM, the commission ~~shall~~ may consider, but is not limited to only considering, the expected magnitude of the impact of the utility's approved demand-side programs on the utility's costs, revenues, and earnings, the ability of the utility to manage all aspects of the approved demand-side programs, the ability to measure and verify the approved program's impacts, any interaction among the various components of the DSIM that the utility may propose, and the incentives or disincentives provided to the utility as a result of the inclusion or exclusion of cost recovery component, utility lost revenue component, and/or utility incentive component in the DSIM.

COMMENT # 11 – POTENTIAL PENALTY OR ADVERSE CONSEQUENCE LANGUAGE

The MEDA stakeholders express concerns about the language in **4 CSR 240-093(2)(E)** that requires the commission to consider "the incentives or disincentives provided to the utility as a result of the inclusion or exclusion of cost recovery component . . ."

MEDA states the purpose of the MEEIA is to remove barriers and reduce risk to the utilities that are created under the traditional regulatory model of utility cost recovery. MEDA claims Section 393.1075, RSMo. contains no support for "penalties" or "adverse consequences." All references, or implications, to penalties or adverse consequences, and recommends that any such language be removed from each of the four proposed rules relating to the MEEIA, with the exception of 4 CSR 240-20.094(7)(B) as it was explicit in the underlying statute.

RESPONSE AND EXPLANATION OF CHANGE: The commission believes that MEDA's concern with this language is unfounded. MEDA is misreading the section. To provide further clarity, however, the commission will add the following two sentences:

In this context the word "disincentives" means any barrier to the implementation of a DSIM. There is no penalty authorized in this section.

COMMENT # 12 – 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: The commission will not modify the language in 4 CSR 240-20.093(4) 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 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), (2)(F), (2)(G), (2)(H) and (2)(J). These changes should provide clarification to this issue. These changes include:

Changes for 4 CSR 240-20.093(1):

(I) Cost recovery component of a DSIM means the methodology approved by the commission in a <u>utility's filing for</u> demand-side program approval ~~proceeding~~ to allow <u>the utility to receive</u> recovery of costs of approved demand-side programs with interest;

(J) Demand means the rate of electric power use ~~measured~~ over an hour <u>measured</u> in kilowatts (kW);

(N) 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 <u>to provide the utility with cost recovery of demand-side program costs based on the approved cost recovery component of a DSIM</u>;

(P) DSIM revenue requirement means the sum of the DSIM cost recovery revenue requirement, DSIM utility lost revenue requirement, and DSIM utility incentive revenue requirement, ~~if allowed by the commission in utility's last filing for demand-side program approval~~;

(Q) 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 <u>on the approved utility incentive component of a</u> 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~~;

(R) 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 <u>utility with</u> recovery of lost revenue <u>based on the approved utility lost revenue component of a DSIM</u>;

(T) Energy means the total amount of electric power that is used ~~by customers~~ over a specified interval of time measured in kilowatt-hours (kWh);

<u>(FF) Utility lost revenue component of a DSIM means the methodology approved by the commission in a utility's filing for demand-side program approval to allow the utility to receive recovery of lost revenue; and</u>

Changes for 4 CSR 240-20.093(2):

(F) Any cost recovery component of a DSIM shall be based on costs of demand-side programs approved by the commission in accordance with 4 CSR 240-20.094 Demand-Side Programs. Indirect costs associated with demand-side programs, including but not limited to costs of utility market potential study and/or utility's portion of statewide technical reference manual, shall be allocated to demand-side programs and thus shall be eligible for recovery through an approved DSIM. The commission shall approve ~~order~~ any cost recovery component of a DSIM ~~approval~~ simultaneously with the programs approved in accordance with 4 CSR 240-20.094 Demand-Side Programs ~~or in a semi-annual DSIM rate adjustment case~~.

(G) Any utility lost revenue component of DSIM shall be based on energy or 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.

1. A utility cannot recover revenues lost due to utility-demand side programs unless it does not recover the fixed cost as set in the last general rate case, i.e. actual annual billed system kWh is less than the system kWh used to calculate rates to recover revenues as ordered by the Commission in the utility's last general rate case.

2. The commission shall order any ~~DSIM~~ utility lost revenue component of a DSIM ~~requirement~~ simultaneously with the programs approved in accordance with 4 CSR 240-20.094 Demand-Side Programs.

3. In a utility's filing for demand-side program approval ~~proceeding~~ in which a utility lost revenue~~s~~ component of a DSIM is ~~are~~ considered there is no requirement for any implicit or explicit utility lost revenue component of a DSIM ~~recovery~~ or for a particular form of a lost revenue component of a DSIM.

4. The commission may address lost revenues solely or in part, directly or indirectly, with a performance incentive mechanism through a utility incentive component of DSIM.

5. Any explicit utility lost revenue component of a DSIM shall be implemented on a retrospective basis and all energy and demand savings to determine a DSIM utility ~~for claimed~~ lost revenue~~s~~ requirement must be measured and verified through EM&V prior to recovery.

(H) Any utility incentive component of a DSIM shall be based on the performance of demand-side programs approved by the commission in accordance with 4 CSR 240-20.094 Demand-Side Programs and shall include a methodology for determining the utility's portion of annual net shared benefits achieved and documented through EM&V reports for approved demand-side programs. Each utility incentive component of a DSIM shall define the relationship between the utility's portion of annual net shared benefits achieved and documented through EM&V reports, annual energy savings achieved and documented through EM&V reports as a percentage of annual energy savings targets, and annual demand savings achieved and documented through EM&V reports as a percentage of annual demand savings targets.

1. Annual energy and demand savings targets approved by the commission for use in the ~~DSIM~~ utility incentive component of a DSIM are not necessarily the same as the incremental annual

energy and demand savings goals and cumulative annual energy and demand savings goals specified in 4 CSR 240-20.094(2).

2. The commission shall order any ~~DSIM~~ utility incentive component of a DSIM ~~revenue requirement~~ simultaneously with the programs approved in accordance with 4 CSR 240-20.094 Demand-Side Programs.

3. Any utility incentive component of a DSIM shall be implemented on a retrospective basis and all energy and demand savings used to determine a DSIM utility incentive revenue requirement must be measured and verified through EM&V.

(J) If the commission approves ~~a DSIM~~ utility incentive component of a DSIM, such utility incentive component shall be binding on the commission for the entire term of the DSIM, and such DSIM shall be binding on the electric utility for the entire term of the DSIM, unless otherwise ordered or conditioned by the commission when approved.

COMMENT # 13 – IMPLEMENTATION OF DSIM

Staff has concerns with the uncertainty regarding the operation of language in **4 CSR 240-20.093(5)**. This paragraph states the following:

> (5) Implementation of DSIM. Once a DSIM is approved, modified or discontinued by the commission, the utility shall use deferral accounting using the utility's latest approved weighted average cost of capital until the utility's next general rate proceeding. At the time of filing the general rate proceeding subsequent to DSIM approval, modification or discontinuance the commission shall use an interim rate adjustment order to implement the approved, modified or discontinued DSIM.

Staff is uncertain regarding the operation of language in 4 CSR 240-20.093(5) as drafted by MEDA and recommends that the language in this paragraph be removed. Specifically, Staff believes the meaning of the reference to "deferral accounting" in this section is unclear. In general, "deferral accounting" means a process of capturing an increased level of expense as a regulatory asset or liability on a utility's balance sheet instead of immediately charging the increased expenses against earnings on its income statement. The normal effect of deferral accounting is to hold the utility harmless from certain adverse earnings impacts until such time that the increased costs can be reflected in the utility's rates.

Based on this understanding, Staff interprets the use of the term "deferral accounting" in the proposed MEEIA rules as allowing the utility to defer the impact of increased DSIM costs on its balance sheet until such time that the utility can reflect the increased DSIM costs in its rates through either a DSIM or a general rate proceeding. If this interpretation is accurate, Staff opposes this provision. Staff believes that allowing for both deferral accounting and the opportunity for expedited rate recovery of DSIM costs is unnecessary and may go beyond the intent of the MEEIA. If a utility is able to avoid charges against income related to increased DSIM costs through use of deferral accounting until its next rate case, the primary rationale for expedited rate recovery goes away. Alternatively, if a utility is allowed to adjust its rates to account for increases to its DSIM costs significantly faster than under ordinary ratemaking procedures in this jurisdiction, the need for additional earnings protection for the utility through use of deferral accounting is likewise not evident. For this reason, to the extent that the

Commission adopts procedures allowing for expedited rate recovery of DSIM costs by utilities, Staff recommends that the language in the proposed rule 4 CSR 240-20.093(5) concerning deferral accounting be removed.

As an additional concern, Staff also notes that the provision regarding "deferral accounting" provides for use of the utility's weighted average cost of capital as part of the deferral process. Applying an interest rate to deferred costs has the impact of holding the utility financially harmless concerning the time-value of money while it waits for recovery of its increased costs through customer rates. Elsewhere in the proposed rule (4 CSR 240-20.093(10)), though, the applicable language specifies that any refunds given back to customers as a result of subsequent prudence reviews of DSM expenditures are to have interest applied to the refund amounts at a rate equal to the utility's short-term borrowing rate. In almost all circumstances, a utility's weighted average cost of capital will be significantly greater than its short-term borrowing rate. Under the proposed MEEIA rule language, then, utilities will be compensated for the time-value of monies owed them through the DSIM at a higher interest rate than customers will receive for the time-value of monies likewise owed back to them on account of the DSIM. Absent a specific demonstration that a utility's cost of capital is in fact higher than its customers' average cost of capital, such a differential is not warranted, and the two rates of interest should be set equally if deferral accounting of DSIM revenue requirements is allowed. In this event, Staff recommends that the utility's short-term borrowing rate be used for both purposes.

Ultimately, Staff recommends elimination or modification of the language referenced under the heading, "Demand-Side Investment Mechanism (DSIM) Approval and Rate Changes Outside of a General Rate Case Proceeding" to reflect that DSIM rates may only be authorized and changed in general rate cases. However, if the Commission disagrees with the Staff on the legal issue regarding authorizing or permitting changes to the rates of a DSIM outside of a general rate case proceeding and this language remains in the rules, Staff still has additional concerns with related language regarding simultaneous approval of demand-side programs and a DSIM as drafted by MEDA, and recommends that modifications be made consistent with the comments above.

RESPONSE AND EXPLANATION OF CHANGE: The commission agrees that this language requires clarification, but it does not wish to foreclose any potential methods of accounting that might facilitate the implementation of MEEIA. Consequently, the commission will make the following modification to the first sentence of this subsection:

5) Implementation of DSIM. Once a DSIM is approved, modified or discontinued by the commission, the utility ~~shall use~~ may request deferral accounting using the utility's latest approved weighted average cost of capital until the utility's next general rate proceeding.

COMMENT # 14 – PRUDENCE REVIEWS

The MEDA stakeholders express concerns over the language in 4 CSR 240-20.093(10)(B). The current language does not allow sufficient time to review Staff's report and request a hearing prior to the scheduled order date without creating the need to delay the order. The rule should be changed to reduce Staff's time from 180 days to 150 days for filing its initial recommendation with the opportunity to request a hearing changing to 160 days post commencement of the audit to allow time for a hearing and still have the Commission's order issued not later than 210 days post-audit commencement.

RESPONSE AND EXPLANATION OF CHANGE: The commission agrees with MEDA and will adopt the proposed changes.

COMMENT # 15 – SPECIFIC LANGUAGE CHANGES

OPC believes that additional language should be added to various definitions in 4 CSR 240-20.093(1), (2), (7), and (10) 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's suggestions for 4 CSR 240-20.093(1) include:

(I) Cost recovery methodology ~~component~~ of a DSIM means the methodology approved by the commission in a general rate proceeding to allow recovery of costs of approved demand-side programs with interest.

(J) Deemed savings means a pre-determined, validated estimate of energy and peak demand savings attributable to an energy efficiency measure in a particular type of application that an electric utility may use instead of energy and peak demand savings determined through measurement and verification activities.

(J) Demand means the rate at which electric energy is used at a given instant, or averaged over a designated period, usually expressed in kilowatts (kW) or megawatts (MW). ~~the rate of electric power use measured over an hour in kilowatts (kW).~~

(K) Demand response measure or program means measures or a program that decrease peak demand or shift demand to off-peak periods or lower price periods.

(L) Demand-side program means any program conducted by the utility to modify the net consumption of electricity on the retail customer's side of the meter including, but not limited to, energy efficiency measures, load management, demand response, and interruptible or curtailable load programs.

(M) Demand-side programs investment mechanism or DSIM means a mechanism approved by the commission in a utility's general rate proceeding to encourage investments in demand-side programs. The DSIM may include cost recovery mechanisms, in combination and without limitation:

1. ~~Cost recovery of demand-side program costs through c~~ Capitalization of investments in and expenditures for in demand-side programs;

2. Rate design modifications ~~Cost recovery of demand-side program costs through a demand-side program cost tracker~~;

3. Accelerated depreciation on demand-side investments; and

4. Utility incentive based on allowing the utility to retain a portion of the net benefits of ~~the achieved performance level of~~ an approved demand-side program~~s~~ for its shareholders.

(O) DSIM ~~rate~~ charge means the charge on customers' bills for the portion of the DSIM revenue requirement assigned by the Commission to a rate class.

(Q) DSIM utility incentive revenue requirement means the revenue requirement approved by the commission in a general rate proceeding to provide the utility with a portion of annual net shared benefits based on the achieved performance level of approved demand-side programs demonstrated through energy and demand savings measured, ~~and~~ documented and verified through EM&V reports compared to energy and demand savings targets.

(S) Energy means the total amount of electric power that is used by customers over a specified interval of time measured in kilowatt-hours (kWh) or megawatt-hours (MWh).

(T) Energy efficiency means equipment, materials, and practices at a customer's site that result in a reduction in electric energy consumption, measured in kilowatt-hours (kWh), or peak demand, measured in kilowatts (kWs), or both. These measures may include thermal energy storage and removal of an inefficient appliance so long as the customer need satisfied by the appliance is still met. ~~measures that reduce the amount of electricity required to achieve a given end-use.~~

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

(W) 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.

(Z) 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 endues 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 benefits shall be calculated over the projected life of the measures installed under the program.

OPC's suggestions for 4 CSR 240-20.093(2) include:

(C) The commission shall approve the establishment, continuation or modification of a DSIM and associated tariff sheets if it finds the DSIM will assist the commission's efforts to implement state policy contained in section 393.1075, RSMo to:

1. ~~Provide the electric utility with timely recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs~~ Value demand-side investments equal to traditional investments in supply and delivery infrastructure;

2. ~~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; and~~ Allow recovery of all reasonable and prudent costs of delivering cost-effective emand-side programs.

~~3. Provide timely earnings opportunities associated with cost-effective measurable and/or verifiable energy and demand savings.~~

(F) Any cost recovery component of a DSIM shall be based on costs of demand-side programs approved by the commission in accordance with 4 CSR 240-20.094 Demand-Side Programs. Indirect costs associated with demand-side programs, including but not limited to costs of utility market potential study and/or utility's portion of statewide technical reference manual, shall be allocated to demand-side programs and thus shall be eligible for recovery through an approved DSIM. The commission shall order any DSIM ~~rates~~ charges in a general rate proceeding *or in a semi-annual DSIM rate adjustment case.*

(G) Any utility incentive component of a DSIM shall be based on the performance of demand-side programs approved by the commission in accordance with 4 CSR 240-20.094 Demand-Side Programs and shall include a methodology for determining the utility's portion of annual net shared benefits achieved and documented through EM&V reports for approved demand-side programs. Each utility incentive component of a DSIM shall define the relationship between the utility's portion of annual net shared benefits achieved and documented through EM&V reports, annual energy savings achieved and documented through EM&V reports as a percentage of annual energy savings targets, and annual demand savings achieved and documented through EM&V reports as a percentage of annual demand savings targets.

(J) In instances where costs that make up the DSIM revenue requirement cannot be directly assigned to rate classes, tThe Commission shall apportion to each of the rate classes the portion of the DSIM ~~revenue~~ requirement that is not directly assigned to rate classes as follows:

1. The utility shall ~~estimate the demand-related portion and the energy-related~~ allocate the portion of demand-side costs that cannot be directly assigned to rate classes ~~using the relationship between the demand-related and energy-related avoided costs that were used to justify the demand-side program weighted by the demand and energy reductions that were used to justify the demand-side program~~ based upon the proportion of total directly assignable demands-side costs that have been directly assigned to each rate class.

~~2. The demand-related portion will be allocated to the rate classes on the contribution to seasonal peak demand of each rate class. For demand-side programs that impact the summer peak, the allocation will be based on the summer peak demand of the classes. For demand-side programs that impact the winter peak, the allocation will be based on the winter peak demand of the classes.~~

~~3. Energy-related costs will be allocated in proportion to the normalized annual energy level of each rate class.~~

~~4. Both demand and energy allocation factors will be adjusted to the generation level.~~

5. In ~~assigning or allocating costs to rate classes, no cost shall be attributed based on the load characteristics of~~ calculating DSIM charges for rate classes with customers who have opted out

of the utility's demand-side programs no charges will be assigned to those customers who have opted out of the utility's demand-side programs but charges will be set at a level that collects the entire DSIM revenue requirement for that rate class from the customers that did not opt out.

OPC's suggestions for 4 CSR 240-20.093(7) include:

(7) Evaluation, measurement and verification (EM&V) of the process and impact of demand-side programs. Each electric utility shall hire an independent contractor to perform and report EM&V of each commission-approved demand-side program in accordance with 4 CSR 240- 20.094 Demand-Side Programs. The commission shall hire an independent contractor to audit and report on the work of each utility's independent EM&V contractor.

(C) EM&V draft reports from the utility's contractor for each approved demand-side program shall be delivered simultaneously to the utility and to parties of the case in which the demand-side program was approved.

(D) EM&V final reports from the utility's contractor of each approved demand-side program shall:

1. Be completed by the ~~utility's~~ EM&V contractor on a schedule approved by the commission at the time of demand-side program approval in accordance with 4 CSR 240- 20.094(3); and

OPC's suggestions for 4 CSR 240-20.093(10) include:

(10) Prudence reviews. A prudence review of the costs subject to the DSIM shall be conducted no less frequently than at twenty-four (24)-month intervals.

1. If the staff, ~~OPC~~ Public Counsel or other party auditing the DSIM believes that insufficient information has been supplied to make a recommendation regarding the prudence of the electric utility's DSIM, it may utilize discovery to obtain the information it seeks. If the electric utility does not timely supply the information, the party asserting the failure to provide the required information must timely file a motion to compel with the commission. While the commission is considering the motion to compel the processing timeline shall be suspended. If the commission then issues an order requiring the information to be provided, the time necessary for the information to be provided shall further extend the processing timeline. For good cause shown the commission may further suspend this timeline.

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 240-20.093(1)(U) and 4 CSR 240-20.093(10) that is completely identical to the OPC's proposed language. Finding there is no distinction between the current language and the proposed changes, 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 # 7.

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 specific suggestions, the commission notes that while it appreciates OPC's suggestions, offering to essentially re-write major portions of the proposed rules 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. A perfect example of this are suggested definitions for "cost recovery methodology," "deemed savings," and "demand response measure or program" – terms that are not used in the proposed rule.

Nevertheless, the commission has examined the remainder of OPC's proposed changes and does not believe they add any clarity to the current language. Finding there is no benefit to the proposed changes at this time 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 240-20.093(14) 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 will be invited to make any suggested modifications during the review process.

COMMENT 16 - CROSS REFERENCE WITH COMMENT 8 IN INTER-RELATED RULE 4 CSR 240-20.094: 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), (2)(F) and (7)(E); and 4 CSR 240-20.094(C).

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

4 CSR 240-20.093 Demand-Side Programs Investment Mechanisms

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

(F) 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;

(I) Cost recovery component of a DSIM means the methodology approved by the commission in a utility's filing for demand-side program approval to allow the utility to receive recovery of costs of approved demand-side programs with interest;

(J) Demand means the rate of electric power use over an hour measured in kilowatts (kW);

(N) 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;

(P) DSIM revenue requirement means the sum of the DSIM cost recovery revenue requirement, DSIM utility lost revenue requirement, and DSIM utility incentive revenue requirement;

(Q) 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;

(R) 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;

(T) Energy means the total amount of electric power that is used over a specified interval of time measured in kilowatt-hours (kWh);

(W) "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."

(X) General rate proceeding means a general rate increase proceeding or complaint proceeding before the commission in which all relevant factors that may affect the costs or rates and charges of the electric utility are considered by the commission;

(Y) 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;

(Z) 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;

(AA) Program pilot means a demand-side program designed to operate on a limited basis for evaluation purposes before full implementation;

(BB) 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;

(CC) Statewide technical resource manual means a document that is used by electric utilities to assess energy savings and demand savings attributable to energy efficiency and demand response;

(DD) 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;

(EE) Utility incentive component of a DSIM means the methodology approved by the commission in a utility's filing for 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;

(FF) Utility lost revenue component of a DSIM means the methodology approved by the commission in a utility's filing for demand-side program approval to allow the utility to receive recovery of lost revenue; and

(GG) Utility market potential study means an evaluation and report by an independent third party of the energy savings and demand savings available in a utility's service territory broken down by customer class and major end-uses within each customer class.

(2) Applications to establish, continue, or modify a DSIM. 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 to establish, continue, or modify a DSIM in a utility's filing for demand-side program approval.

(B) Any party to the application for a utility's filing for demand-side program approval may support or oppose the establishment, continuation, or modification of a DSIM and/or may propose an alternative DSIM for the commission's consideration including, but not limited to, modifications to any electric utility's proposed DSIM. Both, the utility and the commission retain the authority to approve, accept or reject any proposed establishment, continuation, or modification of a DSIM or any proposed alternative DSIM.

(E) In determining to approve, modify, or continue a DSIM, the commission may consider, but is not limited to only considering, the expected magnitude of the impact of the utility's approved demand-side programs on the utility's costs, revenues, and earnings, the ability of the utility to manage all aspects of the approved demand-side programs, the ability to measure and verify the approved program's impacts, any interaction among the various components of the DSIM that the utility may propose, and the incentives or disincentives provided to the utility as a result of the inclusion or exclusion of cost recovery component, utility lost revenue component, and/or utility incentive component in the DSIM. In this context the word "disincentives" means any barrier to the implementation of a DSIM. There is no penalty authorized in this section.

(F) Any cost recovery component of a DSIM shall be based on costs of demand-side programs approved by the commission in accordance with 4 CSR 240-20.094 Demand-Side Programs. Indirect costs associated with demand-side programs, including but not limited to costs of utility market potential study and/or utility's portion of statewide technical resource manual, shall be allocated to demand-side programs and thus shall be eligible for recovery through an approved DSIM. The commission shall approve any cost recovery component of a DSIM simultaneously with the programs approved in accordance with 4 CSR 240-20.094 Demand-Side Programs.

(G) Any utility lost revenue component of DSIM shall be based on energy or 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.

1. A utility cannot recover revenues lost due to utility-demand side programs unless it does not recover the fixed cost as set in the last general rate case, i.e. actual annual billed system kWh is less than the system kWh used to calculate rates to recover revenues as ordered by the Commission in the utility's last general rate case.

2. The commission shall order any utility lost revenue component of a DSIM simultaneously with the programs approved in accordance with 4 CSR 240-20.094 Demand-Side Programs.

3. In a utility's filing for demand-side program approval in which a utility lost revenues component of a DSIM is ~~are~~ considered there is no requirement for any implicit or explicit utility lost revenue component of a DSIM or for a particular form of a lost revenue component of a DSIM.

4. The commission may address lost revenues solely or in part, directly or indirectly, with a performance incentive mechanism through a utility incentive component of DSIM.

5. Any explicit utility lost revenue component of a DSIM shall be implemented on a retrospective basis and all energy and demand savings to determine a DSIM utility lost revenues requirement must be measured and verified through EM&V prior to recovery.

(H) Any utility incentive component of a DSIM shall be based on the performance of demand-side programs approved by the commission in accordance with 4 CSR 240-20.094 Demand-Side Programs and shall include a methodology for determining the utility's portion of annual net shared benefits achieved and documented through EM&V reports for approved demand-side programs. Each utility incentive component of a DSIM shall define the relationship between the utility's portion of annual net shared benefits achieved and documented through EM&V reports, annual energy savings achieved and documented through EM&V reports as a percentage of annual energy savings targets, and annual demand savings achieved and documented through EM&V reports as a percentage of annual demand savings targets.

1. Annual energy and demand savings targets approved by the commission for use in the utility incentive component of a DSIM are not necessarily the same as the incremental annual energy and demand savings goals and cumulative annual energy and demand savings goals specified in 4 CSR 240-20.094(2).

2. The commission shall order any utility incentive component of a DSIM simultaneously with the programs approved in accordance with 4 CSR 240-20.094 Demand-Side Programs.

3. Any utility incentive component of a DSIM shall be implemented on a retrospective basis and all energy and demand savings used to determine a DSIM utility incentive revenue requirement must be measured and verified through EM&V.

(J) If the commission approves utility incentive component of a DSIM, such utility incentive component shall be binding on the commission for the entire term of the DSIM, and such DSIM shall be binding on the electric utility for the entire term of the DSIM, unless otherwise ordered or conditioned by the commission when approved.

(3) Application for Discontinuation of a DSIM. The commission shall allow or require a DSIM to be discontinued or any component of a DSIM to be discontinued only after providing the opportunity for a hearing.

(B) Any party to the utility's filing for demand-side program approval may oppose the discontinuation of a DSIM or any component of a DSIM.

(4) Requirements for Semi-Annual Adjustments of DSIM Rates, if the Commission Approves Adjustments of DSIM Rates Between General Rate Proceedings. Semi-annual adjustments to DSIM rates between general rate proceedings shall only include adjustments to the DSIM cost recovery revenue requirement and shall not include any adjustments to the DSIM utility lost revenue requirement or the DSIM utility incentive revenue requirement. Adjustments to the DSIM cost recovery revenue requirement may reflect new and approved demand-side programs, approved program modifications, and/or approved program discontinuations. When an electric utility files tariff sheets to adjust its DSIM rates between general rate proceedings, the staff shall examine and analyze the information filed by the electric utility in accordance with 4 CSR 240-3.163(8) and additional information obtained through discovery, if any, to determine if the proposed adjustments to the DSIM cost recovery revenue requirement and DSIM rates are in accordance with the provisions of this rule, section 393.1075, RSMo, and the DSIM established, modified, or continued in the most recent filing for demand-side program approval. The staff shall submit a recommendation regarding its examination and analysis to the commission not later than thirty (30) days after the electric utility files its tariff sheets to adjust its DSIM rates. If the adjustments to the DSIM cost recovery revenue requirement and DSIM rates are in accordance with the provisions of this rule, section 393.1075, RSMo, and the DSIM established, modified, or continued in the most recent filing for demand-side program approval, the commission shall issue an interim rate adjustment order approving the tariff sheets and the adjustments to the DSIM rates shall take effect sixty (60) days after the tariff sheets were filed. If the adjustments to the DSIM cost recovery revenue requirement and DSIM rates are not in

accordance with the provisions of this rule, section 393.1075, RSMo, or the DSIM established, modified, or continued in the most recent filing for demand-side program approval, the commission shall reject the proposed tariff sheets within sixty (60) days of the electric utility's filing and may instead order the filing of interim tariff sheets that implement its decision and approval.

(B) The semi-annual adjustments to the DSIM rates shall reflect a comprehensive measurement of both increases and decreases to the DSIM cost recovery revenue requirement established in the most recent demand-side program approval or semi-annual DSIM rate adjustment case plus the change in DSIM cost recovery revenue requirement which occurred since the most recent demand-side program approval or semi-annual DSIM rate adjustment case.

(5) Implementation of DSIM. Once a DSIM is approved, modified, or discontinued by the commission, the utility may request deferral accounting using the utility's latest approved weighted average cost of capital until the utility's next general rate proceeding. At the time of filing the general rate proceeding subsequent to DSIM approval, modification, or discontinuance the commission shall use an interim rate adjustment order to implement the approved, modified, or discontinued DSIM.

(7) Evaluation, Measurement, and Verification (EM&V) of the Process and Impact of Demand-Side Programs. Each electric utility shall hire an independent contractor to perform and report EM&V of each commission-approved demand-side program in accordance with 4 CSR 240-20.094 Demand-Side Programs. The commission shall hire an independent contractor to audit and report on the work of each utility's independent EM&V contractor.

(E) Electric utility's EM&V contractors shall use, if available, a commission approved statewide technical resource manual when performing EM&V work.

(10) Prudence Reviews. A prudence review of the costs subject to the DSIM shall be conducted no less frequently than at twenty-four (24)-month intervals.

(B) The staff shall submit a recommendation regarding its examination and analysis to the commission not later than one hundred fifty (150) days after the staff initiates its prudence audit. The timing and frequency of prudence audits for DSIM shall be established in the utility's filing for demand-side program approval in which the DSIM is established. The staff shall file notice within ten (10) days of starting its prudence audit. The commission shall issue an order not later than two hundred ten (210) days after the staff commences its prudence audit if no party to the proceeding in which the prudence audit is occurring files, within one hundred sixty (160) days of the staff's commencement of its prudence audit, a request for a hearing.