IN THE MATTER OF THE CONTINUATION, EXPANSION, AND ENHANCEMENT OF PUBLIC UTILITY ENERGY EFFICIENCY PROGRAMS IN ARKANSAS

DOCKET NO. 13-002-U ORDER NO. 1

IN THE MATTER OF THE REQUEST FOR APPROVAL OF ITS QUICK START ENERGY EFFICIENCY PROGRAMS AND THE TARIFF RELATED TO THE PROGRAM BY OKLAHOMA GAS AND ELECTRIC COMPANY

DOCKET NO. 07-075-TF ORDER NO. 42

IN THE MATTER OF THE REQUEST FOR APPROVAL OF ITS QUICK START ENERGY EFFICIENCY PROGRAMS AND THE TARIFF RELATED TO THE PROGRAM BY THE EMPIRE DISTRICT ELECTRIC COMPANY

DOCKET NO. 07-076-TF ORDER NO. 43

IN THE MATTER OF THE APPLICATION OF ARKANSAS OKLAHOMA GAS CORPORATION FOR APPROVAL OF QUICK START ENERGY EFFICIENCY PROGRAMS

DOCKET NO. 07-077-TF ORDER NO. 49

IN THE MATTER OF THE APPLICATION FOR APPROVAL OF ARKANSAS WESTERN GAS COMPANY'S INITIAL ENERGY EFFICIENCY PROGRAM PLAN

DOCKET NO. 07-078-TF ORDER NO. 41

IN THE MATTER OF THE APPLICATION FOR APPROVAL OF THE ARKANSAS WEATHERIZATION PROGRAM SUBMITTED BY ENTERGY ARKANSAS, INC. SOUTHWESTERN ELECTRIC POWER COMPANY, OKLAHOMA GAS AND ELECTRIC COMPANY, THE EMPIRE DISTRICT ELECTRIC COMPANY, CENTERPOINT ENERGY ARKANSAS GAS, ARKANSAS WESTERN GAS COMPANY AND ARKANSAS OKLAHOMA GAS CORPORATION

DOCKET NO. 07-079-TF ORDER NO. 27
ORDER

This order establishes a process and a timeline for the Arkansas Public Service Commission ("Commission") to resolve issues related to the development and implementation of the second three-year cycle of comprehensive utility energy efficiency ("EE") programs in Arkansas. Some of these issues have been raised by parties and, in some cases, explored through questioning by the Commission during EE tariff proceedings.¹ The issues include guidance regarding utility development of avoided

¹ See, Dockets No. 07-075-TF (Oklahoma Gas and Electric Company), 07-076-TF (The Empire District Electric Company), 07-077-TF (Arkansas Oklahoma Gas Corporation), 07-078-TF (SourceGas Arkansas, Inc., formerly Arkansas Western Gas Company), 07-079-TF (Arkansas Weatherization Program), 07-81-TF (CenterPoint Energy Arkansas Gas), 07-082-TF (Southwestern Electric Power Company), 07-083-TF (Energy Efficiency Arkansas) and 07-085-TF (Entergy Arkansas, Inc.), collectively, the Utilities and program administrators. The Utilities and all parties to these TF dockets that file comments in response to this Order are hereby made parties to Docket No. 13-002-U.
costs, the use of standard cost-benefit tests in EE program and portfolio screening, the
potential inclusion of non-energy-benefits ("NEBs") within EE program benefit
calculations, anticipated diminished federal funding for the Weatherization Assistance
Program for Low-Income Persons ("WAP") and the associated implications for the
statewide Arkansas Weatherization Program ("AWP"), and the continuation of
improved program coordination among utilities and across fuels.² Other timely issues
include guidance regarding future EE performance goals and utility EE incentives.

In this docket the Commission generally proposes a path forward regarding
utility EE program policy for comment from the Utilities and stakeholders that wish to
participate. Furthermore, this docket seeks the input of parties and stakeholders
regarding possible regulatory streamlining for the benefit of all parties, ratepayers, and
the Commission. The Commission intends to resolve these issues and to establish
guidance for the next three-year cycle, taking administrative notice, where appropriate,
of comments, testimony, and exhibits already included in the record of the tariff or
previous generic dockets, as detailed below.

1. The Commission seeks the input of parties regarding the schedule and
process for developing, submitting and approving programs for the
2014-2016 EE cycle.

   a. Scheduling.

The current cycle of utility EE programs approved by the Commission runs
through calendar year 2013. To date, EE program Annual Reports, annual EECR rider

² For example, the inter-fuel/inter-utility weatherization program launched by Oklahoma Gas and Electric
Company ("OG&E") and Arkansas Oklahoma Gas Corporation ("AOG") in the Fort Smith area in mid-
2011 is a pilot program that operates in parallel with the AWP and WAP programs, but serves primarily
non-low-income households.
tariff adjustments, and comprehensive EE program plans have been filed on or around April 1 of each year (continuing adherence to the schedule required for the 2009 program plans under Section 8. B. of the Commission's Rules for Conservation and Energy Efficiency Programs ("C&EE Rules"). Thus, on the current schedule, on April 1, 2013, utilities would file EE program Annual Reports and Workbooks reviewing 2012 program performance, an annual adjustment to their EECR Riders to be effective for the year following July 1, 2013, and comprehensive EE plans for Program Years 2014 through 2016. The Commission notes that, in the absence of further proceedings, under this schedule utilities might begin to develop future programs without further guidance regarding any future EE targets, changes to the utility incentive structure, or other potential policy changes. Also, the 2014-2016 programs would be developed in advance of an opportunity for all parties to review lessons learned from 2012 and early 2013 program performance.

The Commission seeks comments by all parties in reply to the following questions:

1. Should submission of the 2014-2016 program plans be delayed until July 1, 2013 (or some other date), with program approval scheduled for early September, in order to allow time to consider the performance of the first three-year portfolios, to consider the issues raised in this Order, and to further plan and coordinate programs?

2. If so, what, if any change, should be made to the EECR tariff approval schedule?

b. Procedural changes for streamlining and improved policy focus.

---

3 The Commission notes its expectation that the Independent EM&V Monitor ("IEM") will file its Annual Summary Report on EM&V Findings for 2012 EE programs on or about June 1, 2013.
The Commission also notes that preparation, review, and approval of three-year EE Program Portfolios is a substantial undertaking for all parties, which has in the past culminated in a 2-day hearing. Because each utility plan is filed in a separate tariff docket, much of the 2 days is consumed in the procedural mechanics of making a record in nine different hearings (seven utilities and two third-party administrators). In practice, both the Attorney General ("AG") and the General Staff of the Commission ("Staff") have submitted unified testimony addressing all seven utility program plans plus the two statewide programs (AWP and Energy Efficiency Arkansas ("EEA"). While each utility carries the burden of proof in seeking approval of its own programs, in practice, policy matters affecting all programs frequently arise and must be separately adjudicated in each separate proceeding.

The Commission proposes that implementation of a single program policy and approval docket incorporating the three-year plans of all utility EE programs might reduce time spent by parties and the Commission on purely procedural matters and afford more opportunity for discussion and resolution of substantive matters. Under this approach, all comments, testimony, pleadings and reports concerning program approval for each utility’s EE portfolio would be filed in a single docket and considered in a common hearing. A unified docket could allow efficient and informative panels (such as an all-electric-utility panel, an all-gas-panel, or an all-residential EE panel) and better support the creation of a unified record on topics that inherently affect all utilities, such as accounting for the cross-fuel benefits of weatherization, meeting the needs of national accounts customers, expanding the reach and depth of industrial EE programs, or comparing EM&V results. Such an approach might allow a more
productive focus on policy discussions, with the result that individual tariff dockets may become matters of non-controversial compliance, potentially not requiring separate hearings. Finally, this approach should enhance the standardization of programs across utility territories, which is further addressed in other parts of this order. The Commission invites party comments on this approach and recommendations on any other procedural improvements.

2. EE Goals and Incentive Structure:

Two orders established the EE goals now in effect, and the related utility EE performance incentives. First, Order No. 17 of Docket No. 08-144-U (the Sustainable Energy Resources docket) established the following targets as a percentage of retail kWh or therm sales:

<table>
<thead>
<tr>
<th></th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric:</td>
<td>0.25</td>
<td>0.50</td>
<td>0.75</td>
</tr>
<tr>
<td>Gas:</td>
<td>0.20</td>
<td>0.30</td>
<td>0.40</td>
</tr>
</tbody>
</table>

Second, Order No. 15 of Docket No. 08-137-U (the Innovative Ratemaking docket), established that the same numeric targets would be used to determine achievement for the purpose of awarding utility EE performance incentives. Order No. 15 established two levels of utility performance achievement for purposes of awarding incentives: either performance between 80% and 100% of goal, or performance between 100% and 110% of goal. Order No. 15 acknowledged recommendations by various parties that the goals and incentives should promote persistent energy savings, should closely track growing levels of achievement and should place greater emphasis
on hard-to-reach markets and types of services. The Commission also noted that it might in the future include separate demand response ("DR") targets. While the Commission sought to reward long-lasting savings, it ultimately leaned towards simplicity, clarity, and annual assessment of achievement in the design of the initial utility EE incentive mechanism.

**a. Performance targets:**

The Commission proposes, based on past comments and testimony by parties, and on experience to date with implementation, the following targets for 2014-2016:

**Annual Energy Savings as a Percentage of 2012 Retail Sales**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric</td>
<td>1.00</td>
<td>1.25</td>
<td>1.50</td>
<td>3.75%</td>
</tr>
<tr>
<td>Gas:</td>
<td>0.60</td>
<td>0.80</td>
<td>1.00</td>
<td>2.40%</td>
</tr>
</tbody>
</table>

The following considerations suggest that these targets are reasonable:

- The electric utility targets are similar to the "high" case Entergy Arkansas, Inc. presented at its July 31, 2012 Integrated Resource Plan Stakeholder Meeting, which reflect "cost effective achievable DSM" savings of 0.9%, 1.1%, and 1.2% for the years 2014, 2015 and 2016 (Docket No. 07-016-U, Document No. 24, at 199);

- The electric and gas utility targets also are similar to actual savings which have been achieved in other states with mature EE programs and which were cited in testimony in Docket No. 08-137-U, leading to establishment of the first three-year targets in Arkansas;

- A higher achievement case is appropriate within a framework that awards performance incentives starting at 80% of goal and that provides increased
potential earnings under a new system that rewards cumulative performance (as detailed below);

- During this second three-year cycle, certain start-up costs and administrative inefficiencies which hampered progress during 2011 and early 2012 should be reduced;

- Other parts of this Order make proposals that aim to produce further economies of scale and administration that may make higher targets attainable in a cost-effective manner.

- Two of three gas utilities earned incentives during the start-up year of the first cycle, while only one of four electric utilities earned first-year incentives. While gas utility targets were initially set at a lower level to reflect the fact that there are fewer types of equipment that use gas and thus potentially fewer opportunities for saving gas, the success of gas utilities in meeting the lower targets, and the success of gas utilities in meeting higher targets in other jurisdictions, may indicate that more aggressive EE growth may be achievable in the natural gas sector.

b. **Refined utility EE incentive structure:**

The current utility EE incentive is structured as follows: (1) incentives are available within a range from 80% to 110% of target; (2) incentives can be earned at two levels of performance—either performance falling within 80% to 99% of goal, or performance falling within 100 to 110% of goal; (3) goal achievement is measured based on the number of units of energy saved (either kWh or therms); (4) the total amount of
incentives available each year is based in the first phase of the calculation on 10% of program Net Benefits (Net Benefits include all of a program’s EE cost savings over the life of its measures implemented, minus the cost to the utility and ratepayers of implementing the program); (5) however, award of the 10% of Net Benefit annual incentive is capped at either 5% or 7% of approved program budgets, depending on whether performance falls within the first or the second part of the 80% to 110% range.

As currently structured, the incentive mechanism has the following potential shortcomings:

- A utility achieving 99% of target will receive no more incentive than a utility achieving 80% of target, so long as incentive earnings hit the 5%-of-program-budget cost cap. Similarly, a utility achieving 110% of target will earn no more than a utility achieving 100% of target, so long as incentive earnings hit the 7%-of-program-budget cost cap. When the utility moves over the threshold between 99% of target and 100% of target, it will likely see a sudden jump in the amount of the incentive from 5% to 7% of its program budget—potentially a 40% difference in incentive for a 1% increase in performance.4

- Also, while a substantial incentive is available at 20% below the target, the incentive mechanism provides no reward for achievement above 10% over-performance. In this sense, the incentive is weighted towards encouraging at least a minimum level of achievement, rather than encouraging over-achievement.

---

4 I.e., 7% of program budgets is a figure that is 40% more than 5% of program budgets.
Furthermore, the incentive calculation is tied to performance within each program year, and not to the cumulative performance of the approved three-year plan. For instance, there is no reward in year two for making up for under-performance in year one. Also, a utility that delivers 79% performance in year one and 150% in year two might earn less than a utility delivering 80% performance in each year. Since larger and more complex projects take time to develop and implement, program managers may end up spending considerable resources in one year (thereby reducing achievement and reducing cost-effectiveness in that year) for a project delivered in the following year that may or may not increase total incentive earnings.

The total amount of incentives theoretically available based on net benefits (without the percent-of-budget cap), fluctuates with annual performance, the price of natural gas, and other factors. This amount of incentives can fluctuate significantly for reasons beyond the control or actions of the utility. Because the amount of incentives fluctuates, utility managers cannot predict its magnitude or count on how much they might earn.

In practice, the budget-based cap on incentives often controls, limiting incentives to an amount that is below 10% of Net Benefits. This limitation has at least two effects: First, incentives are essentially awarded based on a percentage of program budgets (i.e., either 5% or 7% of program budget). Second, one purpose of the Net Benefits calculation—rewarding program
managers that increase savings through lowering administrative costs or increasing savings relative to administrative cost—is defeated. The usefulness of the net benefits calculation is thus largely limited to informing program planning and approval.

These discontinuities and limitations were perhaps of less consequence during three years of rapid ramp-up, when utilities were striving to simply develop and implement programs at a new scale, than they will be in future years. As programs mature, an incentive that gradually and continuously rewards increased performance over the three-year cycle, and that better rewards management efforts to maximize cost-effectiveness, arguably will better add value for ratepayers and encourage the best efforts of program managers. Therefore, the Commission proposes to refine the current performance incentive so that it meets the goals outlined above. The proposed refined incentive includes the following features:

- Achievement towards a cumulative 3-year goal would be measured and rewarded annually. For instance, a utility meeting 30% of the 3-year goal in year one would be eligible to collect 30% of the 3-year incentive upon proof of such achievement. The same utility meeting 35% of the 3-year goal in year two would be eligible to collect 35% of the 3-year incentive. However, the utility would only be eligible to receive incentives during year one if it achieved at least 50% of the year one share of the three-year total goal. Similarly, it would only be eligible to receive incentives in year two if it achieved 50% of the cumulative two-year portion of the three-year total goal. In year three, the utility will
post final numbers indicating whether its cumulative performance falls short of 80% of the 3-year goal, or whether it falls within a range that earns incentives.

- The current 80-110%-of-goal range within which incentives are available would be extended to a symmetrical 80% to 120% range that better rewards over-achievement;

- Within the 80% to 120% performance range, the incentive amount would rise linearly from 4% of approved program budgets to 8%, based on achievement. The provision of slightly larger incentives at the upper end is appropriate, given higher goals and a wider range within which incentives are available. The slightly lower incentive at 80% achievement (4% of program budgets rather than 5%) allows for symmetry and moves the incentive structure towards a greater focus on achieving the target, rather than on achieving the minimal 80% threshold.

- The total amount of the available incentive would be based on a percentage of the budget of the initially-approved 3-year plan, and thus would remain stable throughout the implementation period.

- The amount of available incentive that a utility earns in any year will be based on the amount of net benefits achieved in that year. Each 3-year plan will include a forecast of expected net benefits, equal to the difference between the net present value of the expected benefits and
the net present value of expected costs. The costs and benefits will be
determined using the TRC test. Thus, as noted in the example above, a
utility achieving 30% of the forecast 3-year net benefits in year one
would receive 30% of the 3-year incentive upon proof of such
achievement. By using net benefits to determine the share of available
earnings awarded, rather than the amount of total available incentives,
the refined incentive mechanism would reward program management
and achievement better than the current incentive mechanism.

- The utility avoided cost portion of the net benefits calculation
  (including predicted natural gas prices and related energy prices)
  would be held constant throughout the 3-year cycle, bringing a further
element of stability to EE program planning and management.
However, in keeping with the Commission’s prior decisions, EM&V
corrections to the expected energy savings achieved by particular
measures or programs would be incorporated annually into the
calculation of net benefits that would be used to allocate utility EE
performance incentives.

- The 80% to 120% threshold and cap would be applied to the total
incentive earned over the 3-year plan; it would not be applied in year
one or year two. In the event that a utility earns an incentive in year
one or year two, but does not reach the 80% threshold level for the
three-year plan, the utility’s EECR would be reduced in year three by
the amount necessary to true-up any incentive over-earnings. However, this outcome would appear to be unlikely, because strong performance in the first two years enables overall 3-year achievement, and it is unlikely that a utility with consistent strong performance would suddenly fall so far short that it would not earn any incentive over the course of the 3-year plan.

The Commission aims through this proposed EE incentive structure to better reward good program management and cumulative achievement and to remove or reduce factors that influence the award of incentives, but which are outside the control of program managers. A graphic representation of several scenarios illustrating the proposed incentive structure is inserted below. The Commission invites comment on whether this proposed approach to the incentive mechanism represents a reasonable and worthwhile adjustment.
Sample Calculations of the Three-Year Shareholder Incentive Mechanism

<table>
<thead>
<tr>
<th>Performance Levels</th>
<th>Percent of Net Benefits Achieved</th>
<th>Percent of Budget Available</th>
<th>Three-Year Available Incentive</th>
</tr>
</thead>
<tbody>
<tr>
<td>Threshold</td>
<td>80%</td>
<td>4%</td>
<td>$4.8</td>
</tr>
<tr>
<td>Target</td>
<td>100%</td>
<td>6%</td>
<td>$7.2</td>
</tr>
<tr>
<td>Exemplary Cap</td>
<td>120%</td>
<td>8%</td>
<td>$9.6</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Scenarios:</th>
<th>Cumulative Net Benefits Achieved (%)</th>
<th>Cumulative Incentive Earned ($mil)</th>
<th>Cumulative Net Benefits Achieved (%)</th>
<th>Cumulative Incentive Earned ($mil)</th>
<th>Cumulative Net Benefits Achieved (%)</th>
<th>Cumulative Incentive Earned ($mil)</th>
<th>Cumulative Net Benefits Achieved (%)</th>
<th>Cumulative Incentive Earned ($mil)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 - Steady Implementation</td>
<td>33%</td>
<td>2.4</td>
<td>67%</td>
<td>4.8</td>
<td>100%</td>
<td>7.2</td>
<td>7.2</td>
<td>7.2</td>
</tr>
<tr>
<td>2 - Slow Build-Up</td>
<td>20%</td>
<td>1.4</td>
<td>40%</td>
<td>2.9</td>
<td>95%</td>
<td>6.8</td>
<td>6.8</td>
<td>6.8</td>
</tr>
<tr>
<td>3 - Exceed the Cap</td>
<td>50%</td>
<td>3.6</td>
<td>90%</td>
<td>6.5</td>
<td>140%</td>
<td>10.1</td>
<td>9.6</td>
<td>9.6</td>
</tr>
<tr>
<td>4 - Miss the Threshold</td>
<td>20%</td>
<td>1.4</td>
<td>45%</td>
<td>3.2</td>
<td>79%</td>
<td>0.0</td>
<td>(4.7)</td>
<td>(4.7)</td>
</tr>
</tbody>
</table>

In Scenario 1, the utility achieves the target amount of net benefits, and earns the target amount of incentive. In Scenario 2, the utility earns an incentive in Year One, even though the performance was below par. In Scenario 3, the utility exceeds the exemplary cap, so the cumulative incentive earned is limited to the cap. In Scenario 4, the utility does not make the 80% threshold by the end of Year Three, and thus must return the incentives from Years One and Two.

3. Avoided costs

The National Action Plan for Energy Efficiency ("NAPEE") states that energy efficiency avoided costs "are the forecasted economic 'benefits' of energy savings."

*Guide to Resource Planning with Energy Efficiency, NAPEE (2007)* at 3-1. NAPEE notes that utility avoided costs typically include both energy and capacity components. *Id.* at 3-2. NAPEE also states that utility avoided costs may include additional components such as line losses, deferred gas infrastructure, reduced costs of ancillary
services, deferred transmission and distribution capacity, the value of hedging fossil fuel prices or reducing them through demand reduction, and savings in water, fuel oil, or other value streams. *Id.* at 3-2 through 3-3. Conceptually, a utility’s avoided cost may be said to place an upper bound on its planned prudent expenditure on cost-effective EE programs. Detailed avoided cost calculations also should inform program design.

As part of its review of EE programs and EECR tariffs in 2012, the Commission directed utilities to respond to a series of questions regarding avoided cost calculations and granted all parties the opportunity to comment on those responses. The Commission synthesizes below the utility and other party comments and proposes guidance for comment by the Parties regarding the future calculation of avoided costs, as they are used in EE program and portfolio development and approval. The Commission notes that calculation of avoided costs for electric utilities is more complicated than for gas utilities because, among other things, of the need to incorporate generation costs and the costs of foreseeable environmental regulation on generation. The discussion below, therefore, focuses on electric utility avoided costs, except where otherwise specified.

**a. Avoided energy costs.**

The Commission notes that, for the energy component of avoided costs, EAI, SWEPICO, and Empire use forecasts based on regional marginal wholesale costs, which take into account the value generated by either selling energy or avoiding the purchase of energy. Docket No. 07-085-TF, Document No. 313, Responsive Testimony of Karen Radosevich, Exhibit KMR-2 at 1; Docket No. 07-082-TF, Document No. 212, Responsive Testimony of William K. Castle at 5-6; Docket No. 07-076-TF, Document No. 145, Direct
Testimony of Todd Tarter at 4. Based on its review of the filings to date, the Commission proposes that the market-based approach is reasonable and appropriate.

OG&E states that, because it dispatches and commits its own units to serve its load, OG&E relies on a cost-of-service methodology, rather than a market-based energy cost forecast. Docket No. 07-075-TF, Document No. 159, Howell Direct at 2. OG&E indicates that it does not include the value of re-sales of energy saved by EE programs, but rather only the value of avoided wholesale purchases. Id. at 3. The Commission believes that a cost-of-service methodology may be appropriate if OG&E does not, in fact, engage in wholesale transactions. However, if OG&E does engage in wholesale sales of energy, and if EE programs do in fact free up energy that may be sold into the SPP market (or avoid purchases that would have had to be made from the market), then OG&E should impute the value of such sales into the EE cost-effectiveness assessments.

In sum, the Commission proposes as guidance for the next 3-year EE program cycle that, whether a utility uses a market-based method of forecasting avoided energy costs, or a production-cost method, the value of energy freed up by EE programs and sold into the wholesale market, or purchases from the market that are avoided, should be included in the calculation of the costs avoided by EE programs.

AG witness William Marcus recommends that the Commission should move electric utilities toward avoided energy costs that are seasonally differentiated and time differentiated, in order to assign the appropriate higher value of energy for measures that particularly reduce peak usage. See, for instance, Docket No. 07-081-TF, Document No. 242, Marcus Direct at 7. The Commission agrees that this is appropriate and notes that it appears that electric utilities in Arkansas do incorporate time and
seasonality in avoided energy cost estimates. See, for instance, Docket No. 07-085-TF, Document No. 323, Radosevich Rebuttal at 8. The Commission proposes that utilities include time and seasonal differentiation in avoided energy costs that are adequate to reasonably assess the differentiated energy value of EE at the individual program level, or at the measure level if such measure forms a significant portion of the energy savings for the overall portfolio.

Mr. Castle testifies for SWEPCO that the market-based method of forecasting energy costs takes into account the cost of emissions allowances necessary for compliance with existing environmental regulations (such as those associated with sulfur dioxide ("SO2") and oxides of nitrogen ("NOx")). Docket No. 07-082-TF, Document No. 212, Castle Responsive at 6. According to Mr. Castle, such forecasting also takes into account known or potential closures of non-economically compliant supply options and construction of new economical, compliant supply options. Id. Empire indicates that its market-based energy price forecast also takes into account probable environmental costs. Docket No. 07-076-TF, Document No. 145, Tarter Direct at 4. OG&E also states that its future environmental compliance plans are reflected in the production cost modeling used to calculate its avoided energy costs. Docket No. 07-075-TF, Document No. 159, Howell Direct at 3. The Commission proposes that it is reasonable to conclude that market-based and production-model-based avoided energy costs, if properly performed, take into account the energy portion of compliance costs for existing regulations.

Mr. Castle also testifies that SWEPCO includes an estimate of the cost of future carbon dioxide ("CO2") regulation. Docket No. 07-082-TF, Document No. 212, Castle
Responsive at 6. Empire indicates that its avoided energy cost calculations include several possible levels of environmental cost avoidance, and that the base case includes projected CO2 costs starting in 2015. Docket No. 07-076-TF, Document No. 145, Tarter Direct at 4-5. EAI, however, does not include a future carbon cost in its avoided energy cost: Ms. Radosevich testifies that each utility is in the best position to assess these costs for planning purposes, based on its unique system characteristics. Docket No. 07-085-TF, Document No. 329, Radosevich Supplemental Rebuttal at 5-6.

The AG is not opposed to the inclusion of carbon costs, but does oppose including them on a piecemeal basis for individual utilities without more rigorous analysis. The AG recommends that the Commission should make a statewide determination regarding avoided carbon costs that applies to all utilities. Docket No. 07-081-TF, Document No. 254, Marcus Responsive at 3.

The Commission proposes that, while reasonable minds can differ regarding the exact magnitude of the cost of compliance with greenhouse gas regulation at existing power plants, it is prudent to forecast that the effect of greenhouse gas regulation on energy costs, and thus the associated economic risk, is not zero. While each utility has a different generation portfolio and can expect different economic impacts from

---

5 The Commission notes that on March 27, 2012, EPA proposed a New Source Performance Standard (NSPS) to limit CO2 emissions from new power plants; and that section 111(d) of the Clean Air Act will require EPA to establish CO2 emission limits for existing power plants after it finalizes an NSPS rule for new power plants. Clean Air Act § 111(d)(1) provides (with emphasis added) that "The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 110 under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 108(a) or 112(b)(1)(A) but (ii) to which a standard of performance under this section would apply if such existing source were a new source, and (B) provides for the implementation and enforcement of such standards of performance. Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.

---
greenhouse gas regulation, the Commission proposes that it is reasonable to establish a common per-unit value for the avoidance of greenhouse gas emissions at specific times in the future in order to allow comparable Commission review and approval of EE program plans. The Commission notes that there are many published, independent forecasts of the price of carbon regulation, which have been prepared for the purpose of utility integrated resource planning. The Commission recommends for comment by the Parties that the collaborative parties should identify for Commission adoption and approval one reasonable third-party forecast of the price of CO2 allowances (or a comparable forecast of the cost of environmental compliance per ton of CO2 emissions) for the common use of all Arkansas electric and natural gas utilities. The Commission would expect that the approved carbon price forecast would remain in effect throughout the 3-year EE program plan implementation, and would be reviewed again until after the following 3-year program cycle.

b. Avoided capacity costs.

For the capacity component of utility avoided costs, electric utilities currently use the cost of constructing or purchasing a peaking unit (a Combustion Turbine, or “CT”) to determine the value of capacity. Docket No. 07-085-TF, Document No. 323, Radosevich Rebuttal at 6; Docket No. 07-082-TF, Document No. 212, Castle Responsive at 7; Docket No. 07-076-TF, Document No. 145, Tarter Direct at 5. Mr. Castle, for SWEPCO, notes that this “pure capacity” value is a cost to construct a CT, less its energy value. Docket No. 07-082-TF, Document No. 212, Castle Responsive at 7. Mr. Castle also explains that the value of capacity decreases within a surplus market; conversely, it increases as the
market for capacity tightens, and may increase if environmental compliance costs reduce available capacity surpluses. Id. at 7-8. Mr. Castle states that SWEPCO is shifting its methodology for calculating capacity from the approach of using capacity contract terms to one based on predictive modeling. Id. at 6-7. Because the modeling is based on objective, market-based inputs, he states that it will not be confidential and will be more transparent. Id. at 7.

OG&E assumes the avoided capacity cost to be zero in years it does not need additional capacity. Docket No. 07-075-TF, Document No. 159, Howell Direct at 5. Similarly, Mr. Castle provides a chart which indicates that, under the production cost modeling approach that SWEPCO proposes to use in the future, avoided capacity prices are zero during near-term years when there is no projected need for additional capacity, but then have a positive value when SWEPCO needs rise and the capacity market tightens. Docket No. 07-082-TF, Document No. 192, Castle Direct at Figure 1. EAI appears to provide a market-based, levelized capacity cost from the initial program year forward; this cost is escalated based on an index specific to generation capital costs. Docket No. 07-085-TF, Document No. 323, Radosevich Rebuttal, Exhibit KMR-2 at 4. While Empire foresees no need for additional capacity before 2015, it includes a non-zero avoided capacity cost and does not assume a zero capacity cost for any period, because Empire can make sales of energy into the market associated with the avoided capacity. Docket No. 07-076-TF, Document No. 145, Tarter Direct at 5.

EAI indicates that, because its avoided generation capacity is based on the construction cost of a new CT that meets contemporaneous environmental regulations, further avoided environmental compliance costs should not be included for capacity.
Docket No. 07-085-TF, Document No. 313, Radosevich Responsive at 6. EAI similarly states that, because it bases avoided capacity cost on the cost of a new CT, it is not necessary to include further avoided capacity costs related to possible shutdowns, retirements or retrofits of existing fossil generating facilities. *Id.* Empire appears to agree on both points. Docket No. 07-076-TF, Document No. 145, Tarter Direct at 6-7.

SWEPCO indicates that its market-based projections incorporate the effects of environmental compliance and any known reductions in generating capacity. Docket No. 07-082-TF, Document No. 212, Castle Responsive at 8-9. OG&E states that environmental controls are geared towards preserving existing capacity, rather than incremental need, and therefore are not properly included in avoided capacity costs. Docket No. 07-075-TF, Docket No. 159, Howell Direct at 6. OG&E includes two retirements in its avoided capital costs, but includes no shutdowns because it plans none. *Id.*

The Commission proposes that the cost of a CT, as modified to account for market conditions, and as applied to years in which the utility or relevant market area is not in surplus for capacity, is a reasonable proxy for avoided marginal capital costs. The Commission proposes to accept avoided capacity calculations based either on actual prices that are escalated, or on modeling that is based on market data. However, if it is foreseeable that significant investments in environmental controls will cause marginal capacity costs to change, then the Commission proposes that such foreseeable costs should be taken into account. One example, as noted by SWEPCO, is that required investment in environmental controls can lead to retirements or other actions affecting capacity markets. Also, long-term least-cost planning aims to optimize not only the
timing of peaking capacity, but also the cost-effectiveness of each element of the overall portfolio. To the degree that the cost of non-peaking resources may be brought to the margin or avoided during the planning horizon, the Commission proposes that they should be included.

The Attorney General raises the issue of accurately converting avoided capacity values to annual values, and properly aligning those values with annual EE program savings. EAI uses a nominal levelized fix charge rate method to translate the cost of adding a CT in some future year into an annualized cost. Docket No. 07-085-TF, Document No. 323, Radosevich Rebuttal at 7. The AG recommends, however, that avoided CT costs should be annualized by using a modified real economic carrying charge ("RECC") rather than using a nominal levelized value.6 Docket No. 07-081-TF, Document No. 242, Marcus Direct at 4. The AG states that this method more appropriately takes into account the fact that EE measures may have a shorter life than a power plant: a measure that ends in fifteen years, for instance, does not guarantee the avoidance of capacity for the remainder of the 30-year life of a power plant. Id. at 5. Because the EE measure defers such costs rather than avoiding them, the AG argues that a carrying charge, rather than an annual share of avoiding the full cost is more appropriate. Id. The AG provides an example in which the value of deferring a peaking unit under the RECC method rises steadily from approximately $70 per kW-year to more than $120 per kW-year over a thirty year period, rather than remaining a flat $85 under a nominal levelized calculation. Id. at 6.

6 The AG also recommends this approach for avoided generation, transmission and distribution costs. Id.
Entergy witness Radosevich testifies that it is more reasonable to assume that an EE measure reaching the end of its useful life is replaced with a measure of similar or greater efficiency, rather than reverting to its previous level. Docket No. 07-085-TF, Document No. 323, Radosevich Rebuttal at 7-8. Under these circumstances, Ms. Radosevich states, a levelized nominal fixed charge rate is a reasonable way to annualize the long term value of avoided generation capacity. *Id.* at 8.

The Commission recognizes that either the levelized nominal charge or the RECC method may provide a reasonable estimate of the value of capacity avoided for long-lived measures, particularly in cases where the measure avoids capacity from the first year forward. If, however, a measure life is short and capacity is not needed immediately, the RECC method may more accurately align program savings with capacity actually avoided; the RECC method also may more accurately reward the kind of deep energy savings sought under the Commission’s comprehensive EE framework. As such, the Commission proposes to adopt the RECC methodology for calculating EE avoided capacity savings.

c. Transmission and distribution.

EAI bases its avoided cost of transmission and distribution ("T&D") on a levelized average of the actual cost of completed substation upgrade and line upgrade project costs in the Entergy Electric System over the past five years. Docket No. 07-085-TF, Document No. 313, Radosevich Responsive, Exhibit KMR-2 at 7. EAI notes that, unlike generation costs, avoided T&D costs are location and facility specific, and may be difficult to unambiguously identify. *Id.* at 9.
SWEPCO calculates avoided transmission capacity based on the annual capital costs associated with spending on expansion (not replacement) of its transmission system. Docket No. 07-082-TF, Document No. 212, Castle Responsive at 9. While SWEPCO agrees that, to the extent a utility can reasonably quantify the value of avoided distribution costs, they are appropriate to include in utility avoided cost calculations, it has not so far included avoided distribution costs. Id. at 10.

Although OG&E states that avoided transmission and distribution capacity costs could be included in cost-effectiveness calculations if avoidable transmission projects are identifiable and their costs are quantifiable, OG&E has not included the avoided cost of transmission in its avoided cost calculations. Docket No. 07-075-TF, Document No. 156, William Brooks Direct at 3-4. Similarly, Empire states that transmission costs of a generator interconnection can be very specific to the project and be very difficult to estimate and that it has not included transmission costs in EE avoided costs to date. Docket No. 07-076-TF, Document No. 145, Tarter Direct at 7. Empire indicates, however, that due to revised resource planning rules in Missouri, Empire will be developing and including avoided transmission costs in future integrated resource plans ("IRPs"). Id. Empire also can agree that it may be appropriate to incorporate geographically-based distribution capacity costs if EE programs are designed to provide specific distribution capacity relief, but Empire notes that demand response tends to be a more appropriate solution in such cases. Id. at 8.

The Commission notes that at least a portion of transmission expansion is driven by load growth and it follows that, to the extent that load is reduced, transmission expenses are avoided or deferred. The Commission also suggests that, while it may be
difficult to precisely identify and attribute the effects of EE on a specific transmission project, nonetheless, assigning a zero value to this avoided cost is clearly incorrect. The Commission therefore proposes, for comment by the parties, that each electric utility develop estimates of avoided transmission substation and line upgrade costs, as well as distribution substation and line upgrade costs, as elements of their avoided costs.

**d. Line losses.**

For both energy and capacity values, SWEPCO uses an average line loss factor to gross up end-use energy savings, translating them to savings at the generator. Document No. 07-082-TF, Document No. 212, Castle Responsive at 11. SWEPCO also uses a peak line loss factor to gross up end-use demand savings. *Id.* EAI also uses average line losses (for each specific customer class) to adjust energy and peak demand savings, and to adjust capacity avoided. Docket No. 07-085-TF, Document No. 313, Radosevich Responsive, Exhibit KMR-2 at 10. OG&E also indicates that it uses average line losses in its annual load forecast. Docket No. 07-075-TF, Document No. 159, Howell Direct at 7. Empire states that on-system sales plus losses are incorporated into its hourly energy and demand cost modeling, and that average system line losses are used as part of DSM program screening. Docket No. 07-076-TF, Document No. 145, Tarter Direct at 8.

The Commission proposes that, because energy and demand reductions effectuated through EE programs are marginal reductions, and because marginal line
losses exceed average line losses, utilities should use marginal line losses to properly reflect the costs avoided by EE programs.7

e. Non-Energy Benefits and EE Program cost-benefit analysis.

The Arkansas Community Action Agencies Association (“ACAAA”) has repeatedly raised the issue of costs that may be avoided by either utilities, ratepayers, or society through EE programs, but which generally have not been included in utility avoided cost calculations in Arkansas. See, Docket No. 06-004-R, Document No. 66, ACAAA Comments, November 21, 2006; Docket No. 08-144-U, Document No. 38, ACAAA Reply Comments April 24, 2009; Docket No. 10-010-U, Document No. 11, ACAAA Comments, March 5, 2010 and Document No. 40, ACAAA Reply Comments, April 6, 2010; and 2012 EE Tariff Dockets, Testimony and Reply Testimony of Theo MacGregor, May 4 and May 19, 2012, respectively — See, for instance, Docket No. 07-079-TF, Document Nos. 85 and 88. These avoidable costs generally may be called “non-energy-benefits,” or “NEBs.” These values are commonly referred to as “benefits” rather than “costs” because they arise particularly in the context of EE program cost-benefit analysis, where they usually constitute a benefit from the ratepayer’s or society’s perspective, rather than in the context of resource planning, which generally takes the perspective of minimizing costs to an individual utility.

Furthermore, certain NEBs may be appropriate for inclusion in some standard cost-benefit tests and not others. For instance, utility perspective NEBs might be included in the Program Administrator Cost (“PACT”) test, the Total Resource Cost (“TRC”) test and the Societal Cost (“SC”) test, because these tests included utility costs.

---

8 The Commission notes that NEBs are not necessarily always unrelated to energy, nor, depending on whether they are viewed from the perspective of the utility, the ratepayer, or society, are they always “benefits” rather than costs. For that reason, they have recently been conceptualized more broadly as “Other Program Impacts,” or “OPIs.” See, Synapse Energy Economics, Best Practices for Energy Efficiency Program Screening, prepared for the National Home Performance Council, July 23, 2012.
and benefits. Customer-perspective NEBS might be included in the Participant Cost ("PC") test, the TRC and the Societal Cost tests, because these tests include participant costs and benefits. Society-perspective NEBs might be included in the Societal Cost test.

ACAAA witness Theo MacGregor supports inclusion of NEBs in utility EE program screening and cost-effectiveness evaluation. Docket No. 07-079-TF, Document No. 85, MacGregor Direct at 4. ACAA supports the TRC test requires inclusion of NEBs.9 Id. Ms. MacGregor states that the reduced costs of service terminations, the value of reduced power plant emissions, and increased economic development spurred by reduced energy costs should be quantified and accounted for in EE program economic assessment. Id. at 4-5. She testifies that there is extensive, peer-reviewed scientific literature that has found that costs related to asthma, heat stress and hypothermia are significantly alleviated through utility weatherization programs. Id. at 5. She points to specific studies required by the Wisconsin PSC and developed for Massachusetts utility EE program administrators that recently quantified these and other program benefits, and other presentations and studies regarding the quantification of benefits related to reductions in fuel price risk, increases in property value. Id. at 5-6. She states that costs related to fuels and utility services other than electricity and natural gas, such as propane and water, are saved by weatherization programs, and that these savings particularly should be attributed to the Arkansas Weatherization Program. Id. at 9.

---

Most Arkansas electric and natural gas utilities indicate that they either currently include in screening EE program cost effectiveness, or are willing to consider including, customer savings in water and wastewater costs, customer savings in unregulated fuels, interactive fuel effects, and reduced customer O&M costs. Docket No. 07-079-TF, Document No. 88, MacGregor Reply at 4. For instance, SWEPCO includes customer O&M savings within TRC and PC tests. Docket No. 07-082-TF, Document No. 212, Castle Responsive at 13. SWEPCO indicates that the benefit of customer water and wastewater savings should be included as a component of the TRC test if the value can be quantified satisfactorily at a reasonable cost, and similarly states that the inclusion of non-utility fuels has conceptual merit, but is difficult to quantify. Id. at 12 and 14. CenterPoint indicates that some of its programs reduce customer water and wastewater usage, and that it would support inclusion of these values in TRC, PC and ST. Docket No. 07-081-TF, Document No. 244, Leger Direct at 5. CenterPoint also could agree to incorporating alternative fuel cost savings in TRC, PC and SC, so long as no fuels are double-counted among jurisdictional utilities. Id. at 5-6. OG&E states that it currently includes significant changes in customer alternative fuel usage in TRC and PC. Docket No. 07-075-TF, Document No. 156, Brooks Direct at 5. Empire indicates that customer alternative fuel use could be included in EE program screening and measure evaluation. Docket No. 07-076-TF, Document No. 145, Tarter Direct at 10.

EAI does not support inclusion in program screening tests of customer savings from water and wastewater, unregulated fuels, or other elements that do not yield ratepayer benefits directly attributable to electric utility service. Docket No. 07-075-TF, Document No. 323, Radosevich Rebuttal, means Exhibit KMR-2 at 12, 15 and 16. EAI
suggests that consideration of such benefits may fall outside the definition of “cost-effective” under C&EE Rules, which provide that cost effective programs must have “a high probability of providing aggregate ratepayer benefits to the majority of utility customers.” *Id.* at 12 (referencing C&EE Rules at § 3). EAI also indicates that the necessary analysis would be expensive and potentially burdensome to customers. *Id.* at 13 and 14.

Regarding other potential NEBs such as reduced customer absenteeism or improved health, SWEPCO states that they are correctly included in the societal cost test variant of the TRC test, but warns that it is not practical to incorporate these values because they are so difficult, expensive, and controversial to determine. Calling the inclusion of these NEBs within the TRC test a “means to an end” to justify expanded program offerings, SWEPCO states that it is more straight-forward to establish a lower TRC threshold for certain programs or use a different test for screening (such as PACT). Docket No. 07-082-TF, Document No. 212, Castle Responsive at 16. SWEPCO notes that inclusion of these NEBs can lead to the criticism that non-program participants are forced to subsidize non-utility services such as increased comfort for program participants. *Id.* OG&E states that it does not include NEBs such as increased comfort and reduced absenteeism, but that they could be included in TRC and PCT if they are quantifiable and meaningful, and the cost of determining them does not outweigh the benefit. Docket No. 07-075-TF, Document No. 156, Brooks Direct at 6. Empire states that it is not a common industry practice to include customer NEBs such as increased comfort or reduced absenteeism in DSM screening. Docket No. 07-076-TF, Document No. 145, Tarter Direct at 11.
While all electric utilities currently include the cost of emissions compliance in avoided costs (i.e., tradable allowances or credits, which do not currently apply to natural gas utilities), no utilities except CenterPoint (and perhaps Empire) currently include in EE program screening an estimate of benefits to society from environmental externalities. Document No. 07-079-TF, Document No. 88, MacGregor Reply at 4; Docket No. 07-076-TF, Document No. 145, Tarter Direct at 11. Empire states that inclusion of environmental adders within the Societal Test is an exception to the general practice of not including NEB’s in DSM screening. *Id.*

No Arkansas jurisdictional utility currently considers an estimate of any reduced economic risk pertaining to reliance on EE rather than investment in supply, and only CenterPoint indicated a willingness to consider this potential NEB. Docket No. 07-081-TF, Document No. 244, Leger Direct at 8; Docket No. 07-079-TF, Document No. 88, MacGregor Reply at 4; SWEPCO calls risk adjustments an arbitrary adjustment in favor of EE programs that is biased in favor of larger EE programs and that ignores the specifics of particular EE and supply side solutions. Docket No. 07-082-TF, Document No. 212, Castle Responsive at 17. SWEPCO suggests that an alternative would be to calculate EE cost-effectiveness under high and low avoided cost scenarios, thereby informing stakeholders of the possible range of likely benefits. *Id.* OG&E’s view is that its reasonable estimate of each cost-effectiveness parameter for EE programs inherently includes risk, and a separate risk assessment is unnecessary. Docket No. 07-075-TF, Document No. 156, Brooks Direct at 6. EAI and Empire suggest that risk is more properly assessed within the IRP process. Document No. 07-085-TF, Document No.
Ms. MacGregor notes that, while there are varying degrees of difficulty in quantifying NEBs, some states have solved this problem by allowing collaborative development of NEB values for review and adoption by regulators. Docket No. 07-079-TF, Document No. 88, MacGregor Reply at 7. Ms. MacGregor requests that the Commission direct the Parties Working Collaboratively ("PWC") to review the available literature on NEBs and to submit consensus NEB values by January 2013, or in the absence of consensus to submit issues still in contention for the Commission to resolve. Id. at 8.

The Commission proposes that NEBs fall into at least three categories:

(a) Benefits to the utility: If a utility weatherization program reduces utility costs to collect customer arrearages, then those reduced arrearage costs are a "utility NEB;"

(b) Benefits to customers: If an electric utility weatherization program reduces the customer's use of wood or propane heat, the reduced customer expense for heating is not an electric utility avoided cost; but it is a "customer NEB." Measureable reductions in customer health costs associated with reduced home infiltration and moisture and increased comfort might be another customer NEB;

(c) Benefits to society not captured in utility or customer NEBs: If the same weatherization program reduces utility emissions, it may reduce the utility's direct cost of complying with environmental regulations. That cost savings is
a traditional avoided cost, often included within the energy component of utility avoided cost calculations. But the positive effect of reduced emissions on environmental resources, general public health, or agricultural production that are not reflected in the cost of regulation are not utility NEBs or customer NEBs: they are “societal NEBs.”

The Commission proposes as a general matter that including all utility and customer costs within the TRC test, without considering the value of all utility and customer benefits, skews the accuracy of the economic evaluation in cases when the magnitude of the non-energy benefits are significant. This effect may, furthermore, be most pronounced in exactly the kinds of comprehensive EE projects the Commission has sought to promote: whole house weatherization that is accessible to all customers, comprehensive analysis and treatment of the building envelope, HVAC and other end-uses for commercial customers, and industrial process improvements that commonly include a host of customer non-energy impacts. The Commission proposes for comment that this potentially significant inaccuracy of TRC analysis could be addressed in one of at least two ways: either (1) parties could collaboratively develop and propose for Commission approval NEB values for inclusion in TRC tests or (2) the Commission could rely for program screening primarily on the PACT test.

Regarding the first option, the Commission suggests that certain customer NEBs inherently have a quantified cost: water, wastewater, and some alternative fuels have

---

10 To the extent that the cost of emissions is included in utility costs of power through retirement of emissions compliance certificates, they are included in utility costs. To the extent that these direct emission costs are less than the true costs of the pollutant, they are externalities and are included in societal NEBs.
regulated or determinable market-based prices. Thus, for instance, each local water and wastewater utility in Arkansas has a residential rate for water usage, and perhaps a weighted average of these rates or of the largest of these might represent the value of water savings. Also, a reasonable average value might be proposed for each alternative fuel avoided by weatherization or other activities.

Other customer NEBs, such as comfort or health, cannot readily be associated with a regulated or market-based price. But as ACAAA has pointed out, at least for the case of weatherization, a body of research is available that explores these values in the context of utility regulation. For these NEBs, in the case of weatherization services, and for the purpose of the next 3-year EE cycle, the parties working collaboratively could review available data and research and recommend by consensus to the Commission those NEBs that can be reasonably quantified and would make a significant difference in EE program screening. As ACAAA recommends, if parties cannot agree on appropriate values, then they could submit values in disagreement for a decision by the Commission.

As an alternative, SWEPCO has recommended primary reliance on the PACT test for program screening. The strengths of this approach may be that it places EE resources on an equal footing with other utility resources and it may be more straightforward than estimating NEBs. Reliance on PACT, however, may introduce an incentive for program administrators to achieve higher net benefits by simply reducing the size of customer rebates, rather than through improved program administration. The Commission notes, however, that cost effectiveness tests may be reported in several forms, and that if PACT tests are reported as a net present value (NPV) rather than a cost-benefit ratio, this effect may be ameliorated. Also, the Commission would retain
the ability to review all standard cost-effectiveness tests, including TRC values that include ratepayer out-of-pocket costs. The Commission therefore requests that parties comment on whether, for the purpose of program screening over the next 3-year EE cycle, it should rely primarily on TRC as modified by collaboratively-developed NEBs, or whether it should adopt PACT as the primary program screening tool.

Regarding societal NEBs, the Commission suggests that, unlike utility and customer NEBs, inclusion of societal NEBs can be said to be a question more of policy judgment than technical accuracy. The Commission is reluctant at this point to require utilities to include an accounting of the broader societal impact of greenhouse gas emissions or other pollutants. However, since public utility service is inherently affected with a public interest subject to determination by the Commission, the Commission proposes that it will consider approval of utility EE programs and portfolios based on SCT analysis including externalities, for those utilities that wish to use SCT as a substitute for or supplement to TRC and PACT analysis. This proposal is consonant with the current Conservation & Energy Efficiency Program ("C&EE") Rules, which require submission of PC, RIM, TRC, and PACT test results and which provide that "the Commission will not limit the costs and benefits that can be considered in the benefit/cost tests to those listed therein" and that "[a]dmnistrators may submit additional economic analyses and benefit/cost test information in support of a proposed program." C&EE Rules at Section 6.A.

In summary, the Commission proposes to continue the flexible approach of requiring the submission of the four standard tests for program and portfolio approval
with the following refinements: either TRC test results as modified by the inclusion NEBs, or PACT results should be the primary means of screening EE programs. Because this Commission has made every effort to promote a comprehensive approach to EE projects and programs, and because the efficiency of individual EE measures can strongly interact, the Commission does not require such screening at the measure level. The Commission also proposes to retain the flexibility to approve education, training, and marketing programs which do not themselves pass TRC or PACT as part of a portfolio that is cost-effective overall. At the portfolio level, the Commission proposes to require EE portfolios to pass the PACT test, in order to ensure that EE programs, as viewed from the utility perspective, are at least as cost-effective as other resource alternatives. Finally, a utility may voluntarily seek approval of either programs or portfolios that meet SCT. Taken together, these proposed guidelines attempt to ensure that the broadest range of individual EE measures may be considered, that the cost effectiveness of energy savings programs is accurately assessed for both the utility and ratepayers as a whole, and that portfolios are cost effective as a utility resource and serve the public interest.

4. Advancing energy efficiency program comprehensiveness and continuous program improvement

In Order No. 17 in Docket No. 08-144-U (the “Sustainable Energy Resources Docket”), the Commission set forth the following Checklist of Factors it will use to determine whether a utility’s proposed EE programs and total EE portfolio are comprehensive pursuant to the C&EE Rules:
Factor 1: Whether the programs and/or portfolio provide, either directly or through identification and coordination, the education, training, marketing, or outreach needed to address market barriers to the adoption of cost-effective energy efficiency measures.

Factor 2: Whether the programs and/or portfolio have adequate budgetary, management, and program delivery resources to plan, design, implement, oversee and evaluate energy efficiency programs.

Factor 3: Whether the programs and/or portfolio reasonably address all major end-uses of electricity or natural gas, or electricity and natural gas, as appropriate.

Factor 4: Whether the programs and/or portfolio, to the maximum extent reasonable, comprehensively address the needs of a customer at one time, in order to avoid cream-skimming and lost opportunities.

Factor 5: Whether such programs take advantage of opportunities to address the comprehensive needs of targeted customer sectors or to leverage non-utility program resources.

Factor 6: Whether the programs and/or portfolio enable the delivery of all achievable cost-effective energy efficiency within a reasonable period of time and maximize net benefits to customers and to the utility system.

Factor 7: Whether the programs and/or portfolio have EM&V procedures adequate to support program management and improvement, calculation of energy, demand and revenue impacts, and resource planning decisions.
As the EE initiative launched by the Commission in 2006 enters its eighth year, the Commission commends the Utilities for their increasingly comprehensive EE programs. Nonetheless, the Commission’s recent review of the records in the Utilities’ 2012 EE tariff dockets11 and particularly the comments on joint inter-utility and inter-fuel program coordination,12 identified several areas for utilities and other stakeholders to further develop program coordination and comprehensiveness, in order to:

1) maximize progress towards least-cost utility service via comprehensive acquisition of all cost-effective demand-side resources, 2) reach or exceed the Commission’s energy efficiency savings targets, and 3) collaborate with stakeholders in continuous program improvement. The Commission believes that the ultimate result of continued collaboration among utilities, across fuels, and among all stakeholders over the next program cycle, should be the development of core EE programs for each rate class that, insofar as possible, have standardized, transparent features that promote comparability across utilities, better understanding and participation by customers, and increased efficiency in delivering EE services by contractors, vendors, suppliers, and trade allies across the state. Specific elements of this proposed goal are detailed below, and the

11 See footnote 1, which lists each of the EE TF dockets.

12 The Joint Report on Inter-Utility and Inter-Fuel Program Coordination ("Joint Report") filed on April 5, 2012, by Southwestern Electric Power Company ("SWEPCO") on behalf of itself, Entergy Arkansas, Inc. ("EAI"), CenterPoint Energy Arkansas Gas ("CenterPoint"), and SourceGas Arkansas, Inc. ("SGA") in each of those companies’ TF dockets notes that while Oklahoma Gas and Electric Company ("OG&E") and Arkansas Oklahoma Gas Corporation ("AOG") participated in discussions of these issues, the two west Arkansas companies did not participate in the development of the Joint Report. Instead, OG&E and AOG filed separate comments on their joint activities in their TF dockets on March 28 and March 29, 2012, respectively. Empire District Electric Company ("Empire") filed comments in its TF docket on April 10, 2012.
Commission invites comments on these elements as well as the proposed timeline for their consideration.

Arkansas’s EE initiative was greatly assisted at its inception by an open, expansive, and highly educational statewide EE collaborative facilitated by the Regulatory Assistance Project under the direction and with the active attendance of Commissioners and Commissioner advisors and consultants during 2006. Following the adoption of the Rules for Conservation and Energy Efficiency Programs ("C&EE Rules") in 2007, the Commission also sponsored and hosted a number of educational, facilitated workshops on EE and sustainable energy resource topics. Beginning in February 2010, at the direction of the Commission in the first EE Roadmap Order issued in each of the EE TF Dockets, the collaborative process (the Parties Working Collaboratively ("PWC")) under the leadership of the General Staff ("Staff") of the Commission became more formalized and has continued to be a valuable tool for developing proposed rules on Evaluation, Measurement and Verification ("EM&V"), selecting an Independent Evaluation Monitor ("IEM"), and developing Self-Direct ("SD") rules for large commercial and industrial customers. Likewise, the collaborative process has addressed implementation issues such as the development of deemed savings values, the creation and updating of the EE Technical Reference Manual and its EM&V Protocols (Versions 1.0 and 2.0), and standards for administrative costs and EE Reporting Needs. Collaboration has also worked well in the creation of the Arkansas Weatherization Program ("AWP") and the Energy Efficiency Arkansas ("EEA") program, which focuses on education and training issues.
In order to more quickly achieve the development of uniform, comprehensive programs that are coordinated statewide across electric and natural gas utilities, to build on past collaborative successes, and to pool limited resources and enable maximum substantive participation by all parties, the Commission proposes implementation of an enhanced statewide collaborative process that would take advantage of expert technical assistance and facilitation to help resolve specific issues, and that would incorporate a decision-making and reporting process that would facilitate stakeholder buy-in and Commission reliance on its results. Such enhanced stakeholder collaboration would fit hand in hand with the procedural reforms suggested at the beginning of this order by producing a single, collaboratively-developed group of program enhancements for in-depth consideration in a single EE policy docket. While the Commission proposes below an initial series of issues for resolution by the collaborative, the Commission intends that it would become a Continuous Program Improvement Collaborative ("CPI Collaborative") with an ongoing mission to maximize the benefits of utility EE programs for ratepayers and for Arkansas. As the Commission envisions it, the CPI Collaborative should include the Utilities, Staff, the Attorney General, and all parties to this docket and any other participants that the Commission may deem appropriate.

The Commission therefore proposes that, under the leadership of Staff, the Utilities and the stakeholders should select and engage a facilitator with extensive experience in the development of utility EE programs to manage collaborative resolution of the issues described below. The CPI Collaborative would aim to reach consensus on each issue addressed, make a record of its decisions for reporting to the Commission, and provide for minority/dissenting reports to the Commission on issues
not resolved by the parties. Following review of comments received in response to this Order, the Commission proposes to establish a procedural schedule for the work to be done by the CPI Collaborative. As noted elsewhere in this Order, the Commission suggests that the Utilities should be allowed additional time to develop the next cycle of EE programs during 2013. The Commission believes that efforts toward formation of the CPI Collaborative and engagement of a facilitator should begin at once, with a view toward informing the development of the next three-year EE programs and portfolios.

The Commission acknowledges that the task of creating coordinated, uniform statewide utility EE programs would involve a significant amount of work: harmonizing programs that have been developed by different utilities and by their different EE contractors will require both expertise in EE program development and operations, and give and take among utilities, including electric and natural gas utilities. Further, significant experience and expertise would be needed to identify and capture any opportunities for program improvement that might be offered by statewide coordination and standardization. The Commission proposes that the Utilities and other members of the CPI Collaborative should hire a consultant, or team of consultants, to assist with the development of coordinated utility EE programs that could be implemented with the beginning of the next 3-year cycle. The consultants should be selected by the CPI Collaborative stakeholders, including the Utilities, but should be independent of the Utilities and other stakeholders, i.e., they should not have financial or business interests with any of the stakeholders. In the event that the CPI Collaborative stakeholders cannot reach a consensus on the selection of the facilitator and consultant(s), the matter will be submitted to the Commission for decision. Both the facilitator and the
consultants should be paid for by using a small portion (i.e., less than one percent) of the total annual energy efficiency program budgets, and the costs should be allocated to all Utilities using the joint-utility cost allocation methods developed by the Utilities for the AWP, EEA, and EM&V programs. The consultants should have demonstrated technical expertise in the design, planning, implementation, and improvement of energy efficiency programs and strong familiarity with best practices in those areas. The Commission proposes that the Collaborative should be the client of the consultants, who are expressly intended to perform tasks separate from the consultants and vendors used by the Utilities and program administrators to design, implement, and evaluate their programs and separate from the EM&V responsibilities performed by the Independent Evaluation Monitor ("IEM"). The Commission believes that the continuous program improvement mission performed by the CPI Collaborative, its facilitator, and its consultants should be an ongoing one, with annual reporting of the Collaborative’s findings and recommendations to the Commission.

Scope of Work for the CPI Collaborative

The overarching objective of the CPI Collaborative would be to assist the Utilities in developing and enhancing EE programs and plans that meet the state’s energy efficiency goals, targets, and objectives and comply with the directives of the Commission. The Commission would expect the CPI Collaborative to promote program consistency across the state, to incorporate lessons learned and best practices from past energy efficiency activities in Arkansas and elsewhere, to identify and assess state-of-the-art program design concepts and EE technologies for future energy efficiency plans, and to generally seek to maximize the customer and utility benefits available from the
energy efficiency programs over time. The Commission's objective in establishing the CPI Collaborative is to elevate the level of understanding of the stakeholders and the Commission on EE planning, programs, and performance; to further increase consistency, transparency, and comparability among programs across the state; to provide a forum for addressing differences among stakeholders; to formalize a process for engaging technical expertise as needed on an ongoing basis; and to set forth a procedure for narrowing the number of issues requiring Commission action, while allowing for the referral of unresolved or contentious issues to the Commission for a decision, with opportunity for stakeholders to object or propose alternative solutions.

Summary of CPI Collaborative Proposed Focus for the 2014-2016 Program Cycle:

The Commission proposes the following initial agenda for the CPI Collaborative:

- Creation of statewide standardized residential, commercial and industrial programs that, insofar as possible:
  - Have the same names and look the same to customers and trade allies and offer the same levels of rebates and types of services to customers;
  - Encourage comprehensive savings opportunities and avoid lost opportunities;
  - Fully capture cross-fuel savings opportunities; and
  - Provide attractive, utility-wide and cross-utility options for commercial national accounts customers.
• For the industrial sector in particular, the CPI Collaborative should develop a statewide standardized custom industrial program that is designed to:
  o build the long-term relationships with individual customers and offer the technical expertise and resources necessary to capture savings from significant process improvements at a significant share of each utility's industrial facilities;
  o offer trustworthy, specialized expertise to those industrial sectors with a large share of load (such as paper, chemicals, and food processing);
  o promote ongoing strategic energy management planning ("SEMP"); and
  o include and build on outreach through the Arkansas Industrial Energy Clearinghouse and Arkansas Manufacturing Solutions.

• For the residential sector, the CPI Collaborative-developed statewide standardized program should:
  o Offer a standardized approach to whole-house, dual-fuel, weatherization, such that auditing, building, and HVAC contractors in any utility program follow the same technically robust, comparable procedures for determining which measures to implement at each home;
Employ the same or similar training and certification and
EM&V procedures;

Include attractive financing options for any cost-effective
comprehensive building fuel envelope measures not covered
by rebates or free services (such as measures needed by
residential customers not eligible for federal Weatherization
Assistance Program ("WAP") co-payments under the AWP),
or measures in addition to free measures provided by the
dual-fuel weatherization program offered by OG&E and
AOG; such financing options might build on the
Commission-approved Home Energy Affordability Loan
("HEAL") Partnership currently being implemented by
CenterPoint);

The CPI Collaborative also should develop and submit for
approval any NEBs appropriate to home weatherization,
pursuant to the cost-effectiveness guidance outlined above.

- The Commission also recommends for comment that the CPI
  Collaborative, during the next 3-year program cycle, develop a
  statewide database that allows centralized reporting and tracking over
time of program participation and energy savings.

The numbered paragraphs below describe this proposed agenda in more detail
and suggest the order of priority for CPI Collaborative consideration and action. As
noted below, some of these topics appear to require resolution prior to the filing and
approval of the next three-year cycle of programs; others can be addressed later and in an ongoing fashion.

1. Standardizing and achieving efficiencies in the delivery of whole-house weatherization services for residential and small commercial customers. The Commission proposes that the CPI Collaborative, or perhaps a subgroup of the larger collaborative that has a particular interest in weatherization and building thermal envelope issues, should develop a standard approach to whole house weatherization activities that would be followed by all utility programs, and ultimately by a single, statewide coordinated utility weatherization program. This approach should allow contractors, customers, and the Commission itself to understand one set of rules for program customer eligibility and referral for services, for building analysis and the ranking and implementation of covered measures, for rebates and incentives to customers and trade allies, for the training and qualifications required of contractors, and for test-in and test-out to facilitate efficient EM&V. The Commission believes exploration of these issues would be furthered by the CPI Collaborative's convening the program administrators of the AWP program, the statewide federally funded Weatherization Assistance Program for Low-Income Customers ("WAP), and the joint-utility dual-fuel weatherization program offered by OG&E and AOG, as well as the other utilities and the state's electric cooperatives, which have experience and expertise in weatherization.
The Commission also proposes that the Collaborative develop appropriate financing mechanisms for statewide weatherization services, for both residential and small commercial buildings, through exploration of the possibility of tapping state or federal revenue bond financing and otherwise leveraging non-utility program resources as a complement to the ratepayer-funded AWP. Innovative financing is currently being explored by the Arkansas Economic Development Commission and its Arkansas Energy Office division, which have expressed interest in participating in collaborative discussions of innovative financing vehicles that may be available. The Commission would welcome and encourage this participation. The Commission notes one example of such funding – the innovative credit union financing program being offered by the HEAL Program Partnership between CenterPoint Energy Arkansas Gas ("CenterPoint") and the William J. Clinton Foundation’s Clinton Climate Initiative. Through the HEAL program CenterPoint provides rebates to residential participants for air infiltration reduction, duct repair, and insulation. The HEAL program is available to all income levels and, through leveraging of utility EE funds, provides a financing mechanism for energy-saving low-interest home improvement loans that are re-paid through payroll deductions. See CenterPoint’s 2011 Annual Report filed in Docket No. 07-081-TF as Document No. 208, Part No. 2 at 13-14.

Because the AWP will be up for renewal in 2013 for the next three-year cycle of EE programming, and because of the possible reduction of
federal funding for the Arkansas WAP in ensuing federal fiscal years, the 
Commission recommends that the Collaborative place this topic on its 
agenda for early action in 2013 and that the Collaborative engage expertise 
from consultants having familiarity with weatherization best practices 
across the U.S.

2. **Developing joint-utility EE services offerings to national accounts customers.** During the June EE CR hearings in Docket No. 07-075-TF, 
Oklahoma Gas and Electric Company witness Billy Dean Pollock testified 
in response to a Commission question that there is merit to working out a 
national chain program with the other utilities because all of the Utilities 
confront the same barriers when they deal with local big-box store 
managers who often lack decisional and budget authority to sign up for EE 
programs. Docket No. 07-075-TF, Pollock, June 14, 2012, Transcript at 
118. The Commission proposes that the CPI Collaborative focus on this 
task in order to avoid program overlap and duplication and, insofar as 
possible, to eliminate confusion over program-type names and standardize 
elements of measures and offerings and the terms of rebates and offered 
program benefits. The Commission envisions this task being accomplished during 2013 so as to inform the upcoming cycle of planning 
for 2014-2016 programs.

3. **Exploring an expanded role in EE planning and implementation for Arkansas Manufacturing Solutions (“AMS”) and the Arkansas 
Industrial Energy Clearinghouse (“AIEC”), which is currently sponsored
by the EEA program administered by the Arkansas Energy Office. The Commission proposes that the CPI Collaborative immediately invite participation by the AIEC and AMS in its activities that focus on industrial EE program improvement during 2013 and thereafter.

4. **Pursuing opportunities to greatly increase participation levels among and achieve deeper energy and demand savings in the industrial sector and retain potential self-direct ("SD") customers in the Utilities’ programs or attract SD customers to return to participation in the Utilities’ programs at the end of the three-year cycle of exemption under Section 11 of the C&EE Rules.**

It is clear from reviewing the program plans of the three largest utilities (EAI, SWEPCO, and CenterPoint) that industrial EE programs are still at their early stages of development and implementation, with relatively low energy-savings goals and customer participation for this sector. The Commission understands that the most successful industrial programs capture more of their EE savings from industrial process improvements, as opposed to simple lighting or HVAC improvements. While recent industrial EE program goals have been low enough to allow utilities to meet their targets without engaging most of the industrial market or relying significantly on improvements to industrial processes, the increasing targets the Commission is proposing will require broader and deeper savings.
As an example, in 2011 EAI’s primary vehicle for reaching the industrial market, the C&I Custom Solutions Program, worked with less than 0.1% of its industrial customers (21 of 22,000) and was limited to lighting, motors, and HVAC equipment and chillers. In 2012 EAI modified this program by opening it to any measure, including industrial process opportunities, with additional measures and bonus incentives for more comprehensive projects. EAI’s Annual Report Workbook indicates that although the Company’s 2011 energy-savings goal for the program was 5,176,000 kWh through 66 participants, the program actually achieved double the savings at 10,275,701 kWh (199% of its energy-savings planning goal), and did this with the participation of less than one-third (21) of the 66 targeted customers and by spending only 71% of the amount budgeted for the program. EAI Program Portfolio Annual Report Excel Workbook in Docket No. 07-085-TF, Document 286, Part 45 at C4, Table 12. EAI must be commended for exceeding goals on a reduced budget, but these initial results may also suggest that much more savings are available with greater participation and more in-depth projects. The Commission acknowledges that EAI aims to expand participation to 199 participants in 2012 and 398 in 2013, of which some will be industrial and some commercial customers.

Likewise, SWEPCO, through its new targeted Commercial and Industrial Standard Offer Program (CISOP), has so far sought to reach a relatively small share of its total industrial customer base and load. In
2011 SWEPCO achieved 97% of its energy savings target (of 7,184,285 kWh) by reaching 33 of its 42 targeted customers, and by spending 93% of its budget for the CISOP. SWEPCO Program Portfolio Annual Report Excel Workbook in Docket No. 07-082-TF, Document 286, Part 45 at C4, Table 2. The Commission notes that SWEPCO has partnered with the Arkansas Manufacturing Solutions and proposed a comprehensive educational program offering that includes industry and industrial process education courses, including:

- Energy 101 Seminars;
- Energy Audits for Industrial Facilities (which focus on production process improvements);
- Industrial Compressed Air Systems Training;
- Pumping System Optimization; and
- Motor Systems Management.

CenterPoint targets the industrial market through its new Large C&I Solutions Program, which includes prescriptive, custom, and direct install components. In 2011 this program was able achieve 440% of goal with 66 of 165 (40%) of planned participants, although with expenditures of 403% of the amount budgeted. CenterPoint Program Portfolio Annual Report Excel Workbook in Docket No. 07-081-TF, Document 208, Part 2 at C4, Table 17. Overall, because utility EE programs have reached a small share of the industrial base so far, it is likely that many industrial
customers do not yet recognize the potential value of utility EE programs in Arkansas.

The Commission believes that by adopting industrial EE program best practices and optimizing them for Arkansas, utilities should be able to reach a larger share of the industrial customer base with options that offer greater value to many industrial customers than would or could have been achieved through the SD option, thereby creating a win-win for industrial customers, utilities, and ratepayers as a whole. The Commission acknowledges the assurances given by each of the utilities during the EECR hearings in June 2012 that they will do what they can to structure their customized energy projects with large industrial customers so as to retain their participation in the utility EE programs or regain their participation in the utility programs during the next three-year program cycle. See, e.g., Docket No. 07-075-TF (OG&E), T. at 207-208. The Commission believes that enhancing the attractiveness to customers of the industrial programs and their ability to promote deeper energy savings would be appropriate for immediate consideration and action by the CPI Collaborative, since all SD customers now granted exemption will be required to re-apply by September 15, 2013, for the exemption during the next three-year cycle. As part of the exploration of these issues and to inform the Collaborative with respect to the impact, approach, and adoption of best practices with the industrial market segment, the
Commission directs the Utilities to respond to the following questions on or before February 1, 2013:

- Given the specialized needs of large industrial facilities and individual manufacturing facilities, should custom industrial EE programs be planned, designed, and implemented separately from programs for commercial customers, rather than as combined C&I programs? What challenges and opportunities are presented by the prospect of separating industrial programs from commercial ones?

- **On the Breadth and Reach of the Utilities' Industrial EE Programs:**
  - How many industrial customers do you have? What is the breakdown of your industrial customer base by Standard Industrial Classification (SIC)? What are the major types of industrial customers in your service territory (e.g., paper manufacturing, chemical manufacturing, food, plastics and rubber, primary metal, agriculture, mining, etc.)?
  - What percentage, cumulatively, of your industrial customers have participated in your programs?
• Of the industrial customers that have participated, what percentage of your total industrial load do they represent?

• What are your plans for expanding and deepening the energy and demand savings within the industrial sector over the next three-year cycle (including numbers and percentages of customers and estimates of achievable energy and demand savings within this sector).

• How many and what percentage of your total industrial load have opted out under the SD program? How many and what percentage of your industrial customers remain eligible for SD exemption?

• **On the Utilities’ Account Management Practices:**

  o Do you provide your industrial customers with an Account Manager, Account Executive, or Sales Representative?

  o If yes, is it within the role of these Account Managers to sell your EE services in addition to selling energy?

  o What percentage of their time is dedicated to selling EE as opposed to other work?
○ Are Account Managers compensated or rewarded for EE sales based on their performance, as they may be with other sales?

○ What energy efficiency training do the Account Managers receive? Do they receive training on how to sell EE services? On EE technologies and opportunities?

• On Strategic Energy Management Plans or MOU Agreements with Industrial Customers:

○ How do you work within your industrial customers’ budgets and capital and production planning cycles?

○ Do you engage with your industrial customers on long-term planning or is your engagement more one project at a time?

○ Have you developed any Strategic Energy Management Plans ("SEMP") with your industrial customers or signed any Memorandum of Understanding agreements around energy efficiency?

○ At what level are you engaged in your EE work with industrial customers? With the facility manager, or more at the CFO or senior management level? How do you engage with large industrials having regional, multi-state, national, or global operations?
o What do you do to maximize the value of your EE programs with industrial customers?

- **On Industrial Process Saving and Tailored Services:**
  o Do you offer any specialized services aimed at the processes specific to the major industry types in your territory?
  o How do you work with them to understand the EE opportunities with their industrial processes? Do you provide them with specialized expertise to improve the energy efficiency of their industrial processes? Or do you connect them with others that do, such as industry-specific EE program delivery contractors?
  o Have you been successful at capturing energy savings with industrial processes? How much and what percent of your total savings with industrial customers was with their process loads?

5. **Developing cost-effective commercial programs**

Separation of industrial EE programs from the current combined C&I offerings, as suggested in item 4 above, would allow the CPI Collaborative to develop a template for a standardized statewide Commercial EE ("CEE") program for small, medium, and large commercial customers that offers audits and a suite of options tailored to meet the needs of these individual businesses. The Commission believes
this task should begin in 2013 in order to inform utility programming, design, and gradual implementation during the next program cycle. With respect to small commercial customers owning or occupying buildings in need of weatherization services, the Collaborative should coordinate its activities with appropriate entities participating in the discussion of item 1 above.

6. Making utility energy efficiency programs more consistent across the state. The Commission proposes that the Utilities should aim to offer programs that have the same (or similar) names, cover the same markets and customer types, cover the same types of end-uses and offer the same (or similar) technical support and financial incentives. The Commission proposes that such standardized programs could be progressively developed through the CPI Collaborative during 2013 and 2014 and implemented by the end of the next 3-year program cycle. Standardized statewide offerings might offer the following benefits:

- Promoting the involvement of various trade allies (e.g., contractors, vendors, product manufacturers, product distributors, architects, engineers, etc.) across utility service territories;
- Promoting access for and reducing confusion for customers that are located in more than one utility service territory, (e.g.,
medium and large commercial, as well as industrial customers and national brands);

- Streamlining evaluation, review, and ongoing program improvement by utilities and other stakeholders;

- Streamlining review in a single docket by the Commission and comparative evaluation of performance across utilities and geographic areas; and

- Enhancing customer education through more consistent messaging.

7. Separating utility programs for new construction activities from retrofit programs. The Commission notes that the Attorney General’s witness William Marcus testified during last summer’s EECR hearings that lost opportunities arise particularly in the new construction market, where efficiency will be lost for decades if it is not acquired today. See, for instance, Direct Testimony of William B. Marcus in Docket No. 07-082-TF (SWEPCO), Transcript at 279. In the same docket, SWEPCO witness Amanda S. Townsend, program manager for SWEPCO contractor Geavista Group, Inc., testified that as part of its program planning enhancements for 2013 and the next planning cycle, SWEPCO intends to monitor and evaluate the new construction market to determine the viability of a new construction program. Docket No. 07-082-TF, Document No. 214, Townsend Responsive at 9. Ms. Townsend noted that in SWEPCO's
service area the new housing market has slowed drastically owing to economic conditions, but that SWEPCO anticipates the economic climate will adjust in future years. *Id.*

In response to questioning from the Commission, SWEPCO's Consumer Programs Manager Phillip A. Watkins testified that economies of scale in the new construction market can be gained by inter-utility and inter-fuel coordination, although he noted that today's low gas prices make it difficult for new construction programs to pass even the least stringent cost-effectiveness tests. Docket No. 07-082-TF, Watkins, T. at 264. Likewise, during Entergy Arkansas, Inc.'s ("EAI") June EECR hearing, EAI Senior Staff Analyst Richard P. Smith testified in response to a question from the Commission that if every utility is potentially considering the new construction market, there is an opportunity for the electric and gas utilities to coordinate their programs, although he noted that EAI's new Energy Star® home construction program is not fuel specific. Docket No. 07-085-TF, Smith, T. at 284.

To the extent that programs for new construction activities are economically justified and not already free-standing, during the next planning and implementation cycle the Commission proposes that the Utilities continue their joint-utility and dual-fuel coordination and draw upon the resources of the CPI Collaborative as they plan for, design, and implement such programs separately from retrofit programs in both the residential and the C&I sectors. The market actors involved in new
construction programs (architects, engineers, building developers, etc.) are different than the actors involved in standard retrofit programs (homeowners, renters, businesses, industries). These different actors may require different marketing approaches, different types of technical support, and different types of incentives. In addition, the Commission notes that new construction programs are especially well-suited for statewide initiatives. The Commission proposes that this topic receive CPI Collaborative attention during 2014, or sooner if the housing and construction industries show signs of quickened activity in the state.

8. **Strengthening utility EE programs with various delivery options to capture the greatest number of participants.** The Commission recently suggested that the EE Reporting Needs Working Group specify that the Utilities should provide a definition of “participation” and report total eligible participants for each program in order to facilitate estimation of program penetration rates. Order No. 14 of Docket 10-010-U, at 10, September 28, 2012. The Commission recognizes that utilities already collect and report program participation information and that the IEM’s EM&V reports for Program Year 2012 will provide the first fully-developed and robust results, including participation data. During the next EE planning and implementation cycle, the Commission proposes that the CPI Collaborative focus on defining and tracking customer participation information at a detailed enough level so as to minimize double-counting of customers across programs and across years. This information would
be very useful for identifying how comprehensive the efficiency programs are over time, as well as identifying the breadth of participation over time.

In addition, the Commission proposes that in the context of developing standardized statewide programs, the CPI Collaborative explicitly address the issue of which delivery vehicles, including, for example, point-of-purchase rebate, upstream rebate, trade ally rebate, direct install (especially for small businesses and residential customers), and prescriptive and custom rebate are optimal for each type of program. The Commission believes that, insofar as possible, state-wide efficiency programs should be supported with state-wide delivery vehicles.

9. **Evaluating and improving utility planning assumptions, so that the EE plans provide a better reflection of the likely energy savings per participant, the cost per participant, and the number of participants.** The Commission notes that program results from 2011 in many cases included significant differences between the projected energy savings and costs and the final results. The Commission expects that, with greater experience in 2012 and implementation of Arkansas-based EM&V, results will begin to better match planning assumptions. Planning assumptions should, to the extent possible, be based on evidence from a utility’s historical activities in Arkansas, from other Arkansas utilities, from efficiency programs offered by the Arkansas utilities or their affiliates in other states, and from efficiency programs offered by other utilities in neighboring states. As the EE planning and implementation process proceed through the next three-
year cycle, the Commission proposes that the Utilities tap the expertise of
the CPI Collaborative to improve upon their planning assumptions. This
task should begin in 2013 and ramp up during 2014.

10. Exploring the benefits and challenges involved in establishing
and maintaining a statewide data base containing information regarding
the energy efficiency activities of all the Utilities. The Commission
proposes that a statewide EE program data base could be developed that
includes all the information that is used in the EE plans, the Annual
Reports and Workbooks, and the EM&V reports. The proposed data base
would include information at the measure level and the customer level,
and should enable users to aggregate and manipulate the data using
standard data base queries and searches. The proposed data base would
be publicly available, be internet-based, and be able to produce a variety of
reports in formats dictated by the user. Such a data base would be
instrumental in allowing utilities to share information and best practices,
and in allowing the Commission and other stakeholders to review on a
more streamlined basis the efficiency activities with significantly less time
and effort than under today’s system. The Commission believes that the
development of such a data base could ultimately facilitate EE reporting
and review of utility programs for comparability. Because this concept
appears to constitute a significant task, the Commission seeks comment
on the benefits and challenges that it might present and a suggested
approach and timeline for the CPI Collaborative to accomplish this during the next three-year cycle of activity.

The Commission invites the Utilities and other parties to provide comment on all of the items discussed above and to propose improvements or modifications to the Commission’s proposed enhanced collaborative approach to improving comprehensiveness, consistency, transparency, and uniformity in the design and implementation of energy efficiency programs.

Ruling

Having considered the evidence presented by the parties in the dockets referenced in this Order and the issues set forth above, the Commission directs that the Utilities and other parties that request to participate in this docket file comments in accordance with the following schedule:

- Utility and other party responses to the proposal to extend the 2014-2016 program plan filing date from April 1, 2013, to July 1, 2013, or another date – on or before noon on January 25, 2013.
- Utility responses to the questions posed in Section 4 regarding enhanced industrial energy efficiency programs – on or before noon on February 1, 2013;
- Initial Comments – on or before noon on February 15, 2013;
- Reply Comments – on or before noon on March 1, 2013.

Following consideration of the responses and comments submitted, the Commission anticipates that it will be possible to issue timely orders providing further guidance on
these issues, including the Commission's proposal to extend the 2014-2016 program plan filing date from April 1, 2013, to July 1, 2013, or another date.

BY ORDER OF THE COMMISSION,

This ___ day of January, 2013.

I hereby certify that this order, issued by the Arkansas Public Service Commission, has been served on all parties of record on this date by the following method:

[ ] U.S. mail with postage prepaid using the mailing address of each party as indicated in the official docket file, or

[ ] Electronic mail using the email address of each party as indicated in the official docket file.

Colette D. Honorable, Chairman

Olan W. Reeves, Commissioner

Elana C. Wills, Commissioner

Kristi Rhude, Secretary of the Commission