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March 27, 2017

via e-filing EXPRESS

Ms. Amy L. Green, Secretary
Kansas Corporation Commission
1500 S. W. Arrowhead Road
Topeka, Kansas 66604-4027

Re: Docket No. 16-KCPE-446-TAR

Dear Ms. Green:

During the evidentiary hearing held in the above-referenced docket, the Commission requested the Gas Utilities provide the Commissioners, General Counsel, and the parties copies of the Code of Colorado Regulations 4 CCR 723.4-4750 through 4 CCR 723.4-5760 and Oklahoma Administrative Code Sections 165:45-23-1 through 165:45-23-9. This letter and the enclosures have been electronically served on those persons listed on the service list in this docket. The Gas Utilities request that you provide the enclosed documents to the Commissioners and the General Counsel.

Sincerely,

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JGF:rr
Enclosure
cc: Attached Service List

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DEMAND SIDE MANAGEMENT

4750. Overview and Purpose.

These rules implement §§ 40-1-102, 40-3.2-101, 40-3.2-103, and 40-3.2-105, C.R.S. for gas utilities required by statute to be rate-regulated. Consistent with statutory requirements, the purpose of these Demand Side Management (DSM) rules is to reduce end-use natural gas consumption in a cost effective manner, in order to save money for consumers and utilities, and protect the environment by encouraging the reduction of emissions and air pollutants. These rules direct natural gas utilities in the design and implementation of programs that will enable sales customers to participate in DSM. The utility shall design DSM programs for its full service customers to achieve cost-effective energy savings, considering factors such as: achievable energy savings, customer benefits, cost effectiveness ratios, adoption potential, market transformation capability and ability to replicate in the utility service territory.

(a) Each utility shall file a DSM plan and application for cost recovery, within the parameters set forth in these rules. Within the application, the utility shall propose an expenditure target, savings target, funding mechanism, and cost-recovery mechanism.

(b) Each utility shall also file an annual DSM report and an application for bonus.

(c) Each utility shall file a measurement and verification report that evaluates the actual implementation and performance associated with its DSM program.

4751. Definitions.

The following definitions apply to rules 4750 through 4760, unless § 40-1-102 provides otherwise.

(a) "Amortization" means the systematic spreading of expenditures or capital costs incurred for DSM programs, through regular accounting entries over a specified period of time.

(b) "Benefit/cost ratio" means the ratio of the net present value of benefits to the net present value of costs, as calculated using the modified TRC test.

(c) "Cost effective" means a benefit/cost ratio of greater than one.

(d) "Demand side management" (DSM) means the implementation of programs or measures which serve to shift or reduce the consumption of, or demand for, natural gas.

(e) "Discount rate" means the interest rate used in determining the present value of future cash flows of DSM costs and benefits, for both forecasted and actual cash flows. The forecasted DSM costs and benefits are used to estimate the cost effectiveness of DSM measures to develop a cost effective DSM portfolio. The actual DSM costs and benefits, which are the actual costs of the program and the documented energy savings, are used to determine net economic benefits for the purpose of calculating the bonus. Discount rate shall be the utility's after-tax weighted average cost of capital (WACC).

(f) "DSM education" means a program, including but not limited to an energy audit, that contributes indirectly to a cost-effective DSM program by promoting customer awareness and participation..

(g) "DSM measure" means an individual component or technology, such as attic insulation or replacement of equipment.

(h) "DSM period" means the effective period of an approved DSM plan.

(i) "DSM plan" means the DSM programs, goals, and budgets over a specified DSM period, generally considered in one year increments, as may be proposed by the utility.

(j) "DSM program" means any combination of DSM measures, information and services offered to customers to reduce natural gas usage.

(k) "Energy efficiency program" see DSM program.

(l) "Gas Demand-Side Management Cost Adjustment" (G-DSMCA) means a rate adjustment mechanism designed to compensate a utility for its DSM program costs.

(m) "Gas Demand-Side Management bonus" (G-DSM bonus) means a bonus awarded to a utility in accordance with § 40-3.2-103(2)(d), C.R.S.

(n) "Market transformation" means a strategy for influencing the adoption of new techniques or technologies by consumers. The objective is to overcome barriers within a market through coordinating tactics such as education, training, product demonstration and marketing, often conducted in concert with rebates or other financial incentives.

(o) "Modified Total Resource Cost test" or "modified TRC test" means an economic cost-effectiveness test used to compare the net present value of the benefits of a DSM program or measure over its useful life, to the net present value of costs of a DSM measure or program for the participant and the utility, consistent with § 40-1-102(5), C.R.S. In performing the modified TRC test, the benefits shall include, but are not limited to, as applicable: the utility's avoided production, distribution and energy costs; the participant's avoided operating and maintenance costs; the valuation of avoided emissions; and non-energy benefits as set forth in rule 4753. Costs shall include utility and participant costs. The utility costs shall include the net present value of costs incurred in accordance with the budget set forth in rule 4753.

(p) "Net economic benefits" means the net present value of all benefits in the modified TRC test, as applied to the utility's portfolio of DSM programs, less the net present value of the costs in the modified TRC test associated with that same portfolio.

(q) "Sales customer" or "full service customer" means a residential or commercial customer that purchases a bundled natural gas supply and delivery service from a utility but does not include customers served under a utility's gas transportation service rate schedules.

4752. Filing Schedule.

(a) Within 120 days of the effective date of this rule, each utility shall file its DSM plan and application for cost recovery.

(I) The utility shall implement its DSM plan and G-DSMCA, as approved by the Commission, by January 1, 2009.

(b) Beginning April 1, 2010 and each April 1st thereafter, each utility shall submit its annual DSM report, application for bonus and DSMCA filing.

(I) The DSMCA shall take effect July 1 of each year for a period of 12 months.

(c) The initial DSM plan filings of natural gas-only utilities shall cover a DSM period of two years. The initial DSM plan filings of natural gas and electric combination utilities shall cover a DSM period of three years. The subsequent DSM plan filings of all utilities shall cover a DSM period of three years unless otherwise specified by the Commission. Subsequent DSM plan applications are to be filed by May 1 of the final year of the current DSM plan.

4753. Periodic DSM Plan Filing.

On the schedule set forth in rule 4752, the utility shall file by application a prospective natural gas DSM plan for Commission approval. The plan shall detail:

(a) The utility's proposed expenditures by year for each DSM program, by budget category; the sum of these expenditures represents the utility's proposed expenditure target as required by § 40-3.2-103(2)(a), C.R.S.

(b) The utility's estimated natural gas energy savings over the lifetimes of the measures implemented in a given annual DSM program period, expressed in dekatherms per dollar of expenditure, and presented for each DSM program proposed for Commission approval; this represents the utility's proposed savings target required by § 40-3.2-103(2)(b), C.R.S.

(c) The anticipated units of energy to be saved by a given annual DSM program, which equals the product of the proposed expenditure target and proposed savings target; this is referred to herein as the energy target.

(d) The estimated dollar per therm value that represents the utility's annual fixed costs that are recovered through commodity sales on a per therm basis.

(e) The utility shall include in its DSM plan application data and information sufficient to describe the design, implementation, oversight and cost effectiveness of the DSM programs. Such data and information shall include, at a minimum, program budgets delineated by year, estimated participation rates and program savings (in therms).

(f) In the information and data provided in a proposed DSM plan, the utility shall reflect consideration of the factors set forth in the Overview and Purpose, rule 4750. At a minimum the utility shall provide the following information detailing how it developed its proposed DSM program:

(I) Descriptions of identifiable market segments, with respect to gas usage and unique characteristics.

(II) A comprehensive list of DSM measures that the utility is proposing for inclusion in its DSM plan

(III) A detailed analysis of proposed DSM programs for a utility's service territory in terms of markets, customer classes, anticipated participation rates (as a number and a percent of the market), estimated energy savings and cost effectiveness.

(IV) A ranking of proposed DSM programs, from greatest value and potential to least, based upon the data required in subparagraph (III), above.

(V) Proposed marketing strategies to promote participation based on industry best practices.

(VI) Calculation of cost effectiveness of the proposed DSM programs using a modified TRC test. Each proposed DSM program is to have a projected value greater than or equal to 1.0 using a modified TRC test, except as provided for in paragraph (f), below.

(VII) An analysis of the impact of the proposed DSM program expenditures on utility rates, assuming a 12-month cost recovery period.

(g) In its DSM plan, the utility shall address how it proposes to target DSM services to low-income customers. The utility shall also address whether it proposes to provide DSM services directly or indirectly through financial support of conservation programs for low-income households administered by the State of Colorado, as authorized by § 40-3.2-103(3)(a), C.R.S. The utility may propose one or more low-income DSM programs that yield a modified TRC test value below 1.0.

(h) In proposing an expenditure target for Commission approval, pursuant to § 40-3.2-103 (2)(a), C.R.S., the utility shall comply with the following:

(I) The utility's annual expenditure target for DSM programs shall be, at a minimum, two percent of a natural gas utility's base rate revenues, (exclusive of commodity costs), from its sales customers in the 12-month calendar period prior to setting the targets, or one-half of one percent of total revenues from its sales customers in the 12-month calendar period prior to setting the targets, whichever is greater.

(II) The utility may propose an expenditure target in excess of two percent of base rate revenues.

(III) The utility may propose an expenditure target lower than the amount required in sub-paragraph (I), above, during an initial phase-in period. The utility must achieve at least the minimum expenditure target within three years of implementing the initial DSM plan.

(IV) Funds spent for education programs, market transformation programs and impact and process evaluations and program planning related to natural gas DSM programs may be recovered without having to show that such expenditures, on an independent basis, are cost-effective; such costs shall be included in the overall benefit/cost ratio analysis.

(i) The utility shall propose a budget to achieve the expenditure target proposed in paragraph (a), above. The budget shall be detailed for the overall DSM plan and for each program for each year and shall be categorized into:

(I) Planning and design costs;

(II) Administrative and DSM program delivery costs;

(III) Advertising and promotional costs, including DSM education;

(IV) Customer incentive costs;

(V) Equipment and installation costs;

(VI) Measurement and verification costs; and

(VII) Miscellaneous costs.

(j) The budget shall explain anticipated increases/decreases in financial resources and human resources from year to year.

(k) A utility may spend more than the annual expenditure target established by the Commission up to twenty-five percent over the target, without being required to submit a proposed DSM plan amendment. Expenditures in excess of twenty-five percent over the expenditure target shall require submittal of a proposed DSM plan amendment.

(l) As a part of its DSM plan each utility shall propose a DSM plan with a benefit/cost value of unity (1) or greater, using a modified TRC test.

(m) For the purposes of calculating a modified TRC, the non-energy benefits of avoided emissions and societal impacts shall be incorporated as follows.

(I) The initial TRC ratio, which excludes consideration of avoided emissions and other societal benefits, shall be multiplied by 1.05 to reflect the value of the avoided emissions and other societal benefits. The result shall be the modified TRC. A utility may propose a different factor for avoided emissions and societal impacts, but must submit documentation substantiating the proposed value.

(n) Measurement and verification (M & V) plan. The utility shall describe in complete detail how it proposes to monitor and evaluate the implementation of its proposed programs. The utility shall explain how it will accumulate and validate the information needed to measure the plan's performance against the standards, pursuant to rule 4755. The utility shall propose measurement and verification reporting sufficient to communicate results to the commission in a detailed, accurate and timely basis.

4754. Annual DSM Report and Application for Bonus and Bonus Calculation.

On the schedule set forth in rule 4752, the utility shall provide the Commission a detailed DSM report and application for bonus.

(a) In the annual DSM report the utility shall describe its actual DSM programs as implemented. For each DSM program, the utility shall document actual program expenditures, energy savings, participation levels and cost-effectiveness.

(b) Annual program expenditures shall be separated into cost categories contained in the approved DSM plan.

(c) For each DSM program, the utility shall compare the program's proposed and actual expenditures, savings, participation rate, and cost-effectiveness; in addition, the utility shall prepare an assessment of the success of the program, and list any suggestions for improvement and greater customer involvement.

(d) The utility shall provide actual benefit/cost results for the overall DSM plan and individual DSM programs implemented during the plan year. The benefit/cost analysis shall be based on the costs incurred and benefits achieved, as identified in the modified TRC test. Benefit values are to be based upon the results of M & V evaluation, when such has been conducted as set forth in rule 4755. Otherwise, the benefit values of the currently approved DSM plan are to be used.

(e) If the annual report covers a year within which an M & V evaluation was completed, the complete M & V results are to be included as part of the annual report.

(f) The utility may file an application for bonus, pursuant to rule 4760. The application for bonus shall include the utility's calculation of estimated bonus applying the methodology set forth in this rule to the utility's actual performance.

(g) The Commission shall determine the level of bonus, if any, that the utility is eligible to collect on the basis of the information included in the report, pursuant to the bonus criteria and process set forth, below.

(I) The primary objective of the bonus is to encourage cost-effective energy savings. The amount of bonus earned, if any, will correlate with the utility's performance relative to the approved savings target (dekatherms saved per dollar expended) and the energy target. Assuming all other factors that affect consumption remain unchanged, effective DSM programs will reduce per customer commodity consumption which may lead to revenue reductions for the utility. Separate from any bonus determined by the Commission, the Commission may authorize a utility to recover a calculated amount of revenue that acknowledges that an effective DSM program reduced the utility's revenue. This amount shall be calculated, beginning with 2009 DSM programs, as follows:

(A) The utility shall calculate a dollar per therm value that represents the utility's annualized fixed costs that are recovered through commodity sales on a per therm basis.

(B) For DSM programs already approved as October 1, 2009, the utility is to file with the Commission a proposed dollar per therm value and the methodology and supporting documentation for the calculation. This value, methodology, supporting documentation and request for approval is to be filed before January 1, 2010.

(C) For DSM programs filed after October 1, 2009, the utility shall include in the DSM Plan Application Filing set forth in rule 4753, a proposed dollar per therm value and the methodology and supporting documentation for the calculation.

(D) To determine the amount to be recovered as discussed in subparagraph (g)(I), above, the dollar per therm value, as approved by the Commission, shall be multiplied by the annualized number of therms saved as the result of the DSM program, as reported in the utility's annual report.

(E) This amount to be recovered shall be recovered through the Demand-Side Management Cost Adjustment (DSMCA), over the same twelve month period in which any approved bonus amount is recovered, as set forth in subparagraph 4752 (b)(I).

(F) For the purpose of inclusion in the above calculation, the annual report shall include the number of therms projected to be saved from the DSM programs in the twelve months following the end of the program year.

(II) As a threshold matter, the utility must expend at least the minimum amount set forth in subparagraph 4753 (g)(I), except during a phase-in period as set forth in subparagraph 4753 (g)(III), in order to earn a bonus.

(III) The bonus amount is a percentage of the net economic benefits resulting from the DSM plan over the period under review. The percentage value is the product of the two factors:

(A) The Energy Factor is determined by the percentage of the energy target achieved by the utility. The energy factor is zero plus 0.5 percent for each one percent above 80 percent of the energy target achieved by the utility.

(B) The Savings Factor is the actual savings achieved divided by the approved savings target. Each of these quantities is expressed in dekatherms saved per dollar expended.

(IV) The following is provided as an example of the bonus calculation, using these illustrative numbers: utility achieves 106 percent of its energy target; the utility's savings target is 15,000 dekatherms per $1 million expended, and the utility's actual savings is 18,000 dekatherms per $1 million.

The energy factor would be: 50% x (106 – 80), or 13 percent

The savings factor would be: 18,000/15,000 or 1.2

The bonus percentage would be: 13% x 1.2, or 15.6 percent. Thus, 15.6 percent of net economic benefits would be the bonus amount.

(h) For the purposes of calculating the bonus, the costs and benefits associated with DSM programs targeted to low-income customers may be excluded as follows:

(I) The costs and benefits associated with a low-income DSM program may be excluded from the calculation of the net economic benefits for the entire DSM portfolio if the modified TRC value for the low-income program is below 1.0

(II) The expenditures and therms saved associated with a low-income DSM program may be excluded from the calculation of the Savings Factor if the therms saved per dollar expended for the low-income program is below the planned savings target for the overall DSM portfolio.

(i) The maximum bonus is twenty percent of net economic benefits or twenty-five percent of expenditures, whichever is less.

(j) Any awarded bonus shall be authorized as a supplement to a utility and not count against its authorized rate of return or be considered in rate proceedings. The awarded bonus shall be recovered through the G-DSMCA over a twelve-month period after approval of the bonus.

4755. Measurement and Verification.

(a) Each utility shall implement a measurement and verification (M & V) program to evaluate the actual performance of its DSM program. The utility shall present its M & V plan as a part of its DSM plan application, pursuant to rule 4753, and shall include the complete M & V evaluation results with its annual DSM report in those years when the M & V is conducted.

(b) As a part of its M & V program, the utility shall, at a minimum, design a M & V plan to evaluate the effectiveness of the actual DSM measures and programs implemented by the utility. The M & V plan shall address: sampling bias; a data gathering process sufficient to yield statistically significant results; and generally accepted methods of data analysis. The M & V plan shall also include an evaluation of free ridership, spillover and the net-to-gross ratio. The M & V evaluation shall be implemented at least once per the DSM plan period. Subsequent DSM plan applications shall reflect the results of all completed M & V evaluations.

(c) The M & V evaluation shall, at a minimum, include the following:

(I) An assessment of whether the DSM programs have been implemented as set forth in its Commission approved DSM plan;

(II) A measurement of the actual energy savings for each DSM program, in dekatherms per dollar expended and in total dollars, and a comparison to the corresponding utility projections in the approved DSM plan;

(III) To the extent feasible, an assessment of the period of time that each DSM measure actually remains in service, and a comparison to the corresponding utility projections in the approved DSM plan;

(IV) A summary of the actual benefit/cost ratio for each DSM program within the approved DSM plan;

(V) An assessment of the extent to which education and market transformation efforts are achieving the desired results; and

(VI) Recommendations for how the utility can improve the market penetration and cost effectiveness of individual DSM programs.

4756. General Provisions Concerning Cost Allocation and Recovery.

(a) Amortization periods.

(I) For the base rate method, the utility shall propose the amortization period. The utility shall specify and explain the rationale for the amortization period proposed for each DSM program as a part of its DSM plan application, filed pursuant to rule 4753.

(II) For the expense method, the utility shall recover the annual expenditures projected for that year over a one-year period.

(b) Fuel switching. Fuel switching from natural gas to other fossil fuel derived energy sources shall not be included in the gas utility's DSM program. Programs to save natural gas through switching to renewable energy sources such as solar heating and ground source heat pumps are allowed.

(c) A utility that provides both regulated gas and electric service shall give consideration to the administrative benefits and reduced costs associated with combining gas and electric DSM activities and shall assign costs and benefits appropriately to each plan.

(d) Distribution of DSM program expenses.

(I) The utility shall include in its portfolio-level benefit/cost analysis all indirect costs relating to DSM, including but not limited to DSM customer education, program design, and evaluation costs.

(II) A utility's existing gas efficiency and conservation customer education tools, such as on-line energy assessment tools or other similar internet based tools, may be included in a utility's gas DSM plan and costs recovered pursuant to the gas DSMCA rule.

4757. Funding and Cost Recovery Mechanism.

The purpose of the G-DSMCA is to enable utilities to recover prudently incurred gas DSM program expenses without requiring a change in their base rates for gas sales. All such costs, plus any G-DSM bonus approved by the Commission, shall be recovered through the G-DSMCA that is set on an annual basis, and collected from July 1 through June 30. The G-DSMCA allows for prospective recovery of prudently incurred costs of DSM programs within the DSM program expenditure target approved by the Commission in order to provide for funding of the utility's DSM programs, as well as recovery of deferred G-DSMCA costs, without having to file a rate case.

(a) A utility may spend a disproportionate share of total expenditures on one or more classes of customers, provided, however, that cost recovery for programs directed at residential customers are to be collected from residential customers only and that cost recovery for programs directed at nonresidential customers are to be collected from nonresidential customers only, except as provided for in paragraph (f), below.

(b) The utility may recover its DSM program expenditures either through expensing or by adding DSM program expenditures to base rates as a part of, or outside of, a rate case, with an amortization period as set forth in rule 4756.

(c) There shall be no financial penalty assessed on a utility for failing to reach its approved DSM program expenditure target, nor shall there be a bonus simply for meeting its DSM program expenditure target. All prudently incurred expenditures for the utility's portfolio of DSM programs are recoverable. However, the portion of costs yielding a modified TRC test value below 1.0 loses its presumption of prudence and is subject to review.

(d) Amounts not spent under the DSM program expenditure target shall not roll-over to the next DSM period.

(e) A utility has the discretion and the responsibility of managing the portfolio of DSM programs to meet the benefit to cost ratio and the energy and savings targets. In implementing DSM programs, a utility shall use reasonable efforts to maximize energy savings consistent with the approved DSM plan.

(f) A utility may continue DSM programs that were in existence on or before May 22, 2007, the effective date of § 40-3.2-103, C.R.S., concerning measures to promote energy efficiency, and shall not be required to obtain approval from the Commission for recovery of costs associated with such programs. Any new expenditure for such programs must be included in the annual DSM plan filing and G-DSMCA application. Existing low-income DSM programs that recover costs from all customer classes shall continue such recovery.

(g) A utility shall file a request to adjust its G-DSMCA factor either through an application or an advice letter and tariffs, pursuant to the relevant provisions of title 40, articles 1 through 7 of Colorado Public Utilities Law and Commission rules. The G-DSMCA shall be filed pursuant to the schedule provided in rule 4752.

(h) A G-DSMCA application shall include information and exhibits as required in rule 4758. If the M & V evaluation required by rule 4755 yields benefit/costs test results that impact the allowable recovery of costs or currently approved bonus, then the utility shall include such adjustments in the G-DSMCA application.

(i) If the projected DSM program costs have changed from those used to calculate the currently effective G-DSMCA cost or if a utility's deferred G-DSMCA cost balance increases or decreases sufficiently, the utility may file an application to revise its currently effective G-DSMCA factor to reflect such changes, provided that the resulting change to the G-DSMCA factor equates to a base rate change of at least one cent ($0.01) per Mcf or Dth. A utility has the burden of proof to justify any interim G-DSMCA filings and the Commission has the discretion to consolidate the interim G-DSMCA filing with the next regularly scheduled annual G-DSMCA filing.

(j) Applicability of the G-DSMCA factor. The G-DSMCA factor shall be separately calculated and applied to the utility sales gas base rate schedules of residential and non-residential customers.

(k) Return on DSM program expenditures to be amortized. For utilities that choose to amortize the DSM program expenditure, the balance of a utility's investments in cost-effective DSM programs shall earn a return equal to the utility's current after-tax weighted average cost of capital.

(l) Interest on under- or over-recovery. The amount of net interest accrued on the average monthly balance in sub-accounts of Account No. 186 (whether positive or negative), is determined by multiplying the monthly balance by an interest rate equal to the Commission-authorized after-tax weighted average cost of capital.

(m) Calculation of the G-DSMCA factor. The G-DSMCA factor shall be calculated separately for residential and non-residential customers to at least the accuracy of two significant places.

4758. Contents of Gas DSM Cost Adjustment Applications.

(a) General Provisions.

(I) An application for a gas DSM cost adjustment (G-DSMCA) shall contain justifying exhibits sufficient in detail to permit the Commission to determine the accuracy of the calculation.

(II) As part of its application for approval of its G-DSMCA, the applicant shall file a complete set of work papers and all other documents relied on in preparing its application.

(III) The provisions of this rule do not supersede other Commission rules that contain additional applicable filing requirements.

(b) Specific Provisions. An application shall contain detailed schedules and supporting documents that establish, at a minimum, the following:

(I) The detailed calculation of the G-DSMCA for each customer class based on the following general formula:

(A) Current G-DSMCA factor = (current G-DSMCA cost + deferred G-DSMCA cost) / (forecasted sales customer x monthly service charge + forecasted sales gas quantity x base rate).

(B) The G-DSMCA factor will also include the current G-DSM bonus plus any adjustment necessary to previously approved G-DSM bonuses.

(II) A detailed schedule showing the computation of interest, as applicable, to deferred amounts.

(III) The absolute and percentage impact of the proposed rate on the base rates and on the total monthly bills of typical customers in each customer class.

(IV) A schedule detailing the allocation of costs to each customer class.

(V) Proposed customer notice detailing rate impact and effective date.

(VI) Proposed tariff implementing the proposed G-DSMCA.

(VII) If any gas DSM costs are proposed to be recovered by rate base treatment, with a return on the unamortized balance, a statement of current net operating earnings, a detailed calculation of the related revenue requirement and an exhibit detailing any differences in the proposed rate base treatment compared to the regulatory practices employed by the Commission in its last general rate case for the applicant.

4759. Bill Itemization.

Consistent with rule 4406, a utility shall provide itemized gas cost information with gas DSM costs to all customers commencing with the first complete billing cycle in which the new rates are in effect.

4760. Gas DSM Bonus (G-DSM Bonus) Applications.

The Commission shall review each G-DSM bonus application submitted and shall determine the level of bonus, if any, for which the utility is eligible. The Commission's determination shall be made within 120 days after receiving the G-DSM bonus application. Any such bonus shall be authorized as a supplement to the DSMCA cost adjustment mechanism and shall be applied over a twelve-month period after approval of the G-DSM bonus and DSMCA. The collection on any G-DSM bonus awarded will be apportioned between residential and nonresidential customers based on the proportion of residential and nonresidential net economic benefits used to calculate the G-DSM bonus. A utility that implements a new DSM program in phases shall be eligible to receive a bonus during its phase-in period.

(a) G-DSM bonus filing requirements. The utility shall file its G-DSM bonus application as part of the annual report submitted to the Commission on the timetable set forth in rule 4752. The utility may request a G-DSM bonus not to exceed the lower of 25 percent of the expenditures or 20 percent of the net economic benefits of the DSM programs, applying the bonus calculation procedure set forth in rule 4754. The G-DSM bonus, as modified and approved by the Commission, shall not count against a gas utility's authorized rate of return or be considered as net operating earnings in rate proceedings.

(b) Contents of G-DSM bonus filing. In the G-DSM bonus filing, the utility shall submit to the Commission the following, at a minimum:

(I) Documented expenditures on DSM programs for the current G-DSMCA period.

(II) Gas savings for the calendar year for which the bonus is to be awarded estimated following and the techniques approved in the DSM plan. The utility shall explain whether the actual gas savings are validated through the measurement and verification process as approved in the utility's DSM plan.

(III) Estimated cost-effectiveness of program expenditures for the current G-DSMCA period in terms of the amount of gas saved per unit of program expenditures.

(IV) Actual gas savings and the techniques used to calculate these gas savings for the prior G-DSMCA period. The utility shall explain whether the actual gas savings are validated through the measurement and verification process, pursuant to rule 4755.

(V) Actual cost-effectiveness of program expenditures for the prior G-DSMCA period in terms of the amount of gas saved per unit of program expenditures. The utility shall explain whether the actual cost effectiveness of program expenditures is validated through the measurement and verification process, pursuant to rule 4755.

(VI) Proposed tariffs containing rates to collect the bonus over 12 months.

(c) Commission procedures for processing filings. Upon receipt of a G-DSM bonus application, the Commission shall assign a docket number and shall review the submittal for completeness as well as for substance, if a request for bonus is made by a utility. The Commission shall entertain interventions by interested parties, require the oral testimony and the filing of exhibits, and permit expedited discovery, and hold a hearing, as necessary. The Commission shall render a decision approving or disapproving the request for bonus within three months after receiving the G-DSM bonus filing.

(d) Accounting for G-DSM bonus. Accounting for G-DSM bonus shall follow what has been prescribed for G-DSMCA costs, specifically in regard to interest on over- and under- recovery. A separate sub-account in Account No. 186 shall be created for any deferred G-DSM bonus amount.

(e) Prudence review and adjustment of G-DSM bonus. If the Commission finds that the actual performance varies from performance values used to calculate the G-DSM bonus in rule 4754, then an adjustment shall be made to the amount of G-DSM bonus award. Any true-up in G-DSM bonus will be implemented on a prospective basis.

4761. – 4799. [Reserved]

MASTER METER OPERATORS

4800. Scope and Applicability.

These rules are applicable to any person who purchases gas service from a utility for the purpose of delivery of that service to end-users whose aggregate usage is to be measured by a master meter or other composite measurement device.

4801. Definitions.

The following definitions apply to rules 4800 through 4805, unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Check-meter" means a meter or other composite measurement device which is used by a master meter operator and which is used to determine gas consumption by end-users served by the master meter operator.

(b) "Master meter" means a meter or other composite measurement device which a serving utility uses to bill a master meter operator.

proceedings.
(b) "Highly Sensitive Confidential" designation and protection shall extend but not be limited to the following: initial Plans (including underlying documents), Plan Update Reports, Certification Letters, Annual Reports made by Commission Staff, recommendations submitted by the Attorney General of the State of Oklahoma and un-redacted documents used in cost recovery proceedings. For all other documents, the "Highly Sensitive Confidential" designation may be granted upon hearing and Final Order of the Commission.
(c) Each utility's Plan and/or Plan Update Report prepared in accordance with this Subchapter, shall be marked "Highly Sensitive Confidential" and shall be kept and maintained on site at the utility's business office in accordance with OAC 165:45-21-7(g), above. Only those individuals on the Staff of the Corporation Commission and in the State Attorney General's office and their respective experts who have been authorized by the Commission, shall have access to the Plan and Plan Update Reports prepared by each utility and any related or supporting documentation thereto. All other parties granted authorized intervenor status to a security cause pursuant to OAC 165:45-21-10(c) may also be granted access to the Plan, Plan Update Reports and supporting documentation after notice and hearing.

[**Source:** Added at 22 Ok Reg 712, eff 7-1-2005]

SUBCHAPTER 23. DEMAND PROGRAMS

Section

165:45-23-1. Purpose

The purpose of this subchapter is to establish fair and reasonable rules for planning and implementing Demand Programs that may receive cost-recovery treatment from the Commission. The rules in this Subchapter shall apply to Demand Portfolios having program years that begin on January 1, 2017 and thereafter.

[**Source**: Added at 26 Ok Reg 1859, eff 6-25-09; Amended at 31 Ok Reg 1067, eff 1-1-2017]

165:45-23-2. Goals

(a) The goals of Demand Programs are to minimize the long-term cost of utility service~~.~~, to encourage and enable utility customers to make the most efficient use of energy, and to discourage the inefficient and wasteful use of energy.

(b) The Commission shall set specific savings goals for each utility to achieve Net Source Energy Usage Savings without adversely affecting customer comfort or state economic activity, based on market potential studies, base line studies, gas supply portfolios, risk management plans, or other evidence presented as part of the hearing process for approval of a utility's Demand Programs.

[**Source**: Added at 26 Ok Reg 1859, eff 6-25-09; Amended at 31 Ok Reg 1067, eff 1-1-2017]

165:45-23-3. Definitions

The following words and terms, when used in this Subchapter, shall have the following meaning, unless the context clearly indicates otherwise:

"Administrative Cost" means the expenses incurred in controlling supporting Demand Programs that are not tied to the marketing and delivery of those programs. These expenses include:

(A) reviewing and selecting Demand Programs in accordance with this section;

(B) providing regular and special reports to the Commission, including reports of Demand Program savings;

(C) a utility's costs for an annual review of Demand Programs or true-up proceeding for cost recovery mechanism;

(D) Supervisory functions performed by Demand Portfolio Manager that are related to supervision of employees and related human resource administration.

"Average customer bill" means the value derived from the sum of all consumer bills in a particular customer sector divided by the number of consumers in that sector; i.e., the arithmetic mean. A utility may use the average customer bills for the customer rate classes rather than the customer sectors if it chooses to do so and clearly identifies the choice.

"Barrier" means any physical or non-physical necessity, obligation, condition, constraint, or requisite that obstructs or impedes natural gas user participation in Demand Programs. Barriers may include but are not limited to language, physical or mental disability, access to capital, educational attainment, utility meter type, economic status, property status, or geography.

"Base line" means natural gas use, trend in natural gas use, and description of conditions affecting such uses and trends prior to implementation of a Demand Program designed to affect particular uses and trends. When evaluating energy efficiency measures implemented as a result of non-fuel switching Demand Programs, the base line to be used in savings calculations shall be either the performance standard base line (the minimum efficiency available in the market), or a customized, project specific base line. When evaluating energy efficiency measures implemented as a result of fuel switching or non-prescriptive Demand Programs, the base line to be used in calculations shall be the replaced equipment efficiency.

"California Standard Practice Manual" means The California Standard Practice Manual: Economic Analysis of Demand Side Programs and Projects, 2001 edition, produced by the California Energy Commission and the California Public Utility Commission.

"Cost effective" and **"cost effectiveness"** mean utilizing a specified amount of money, in a way that delivers a benefit from available alternative uses, so long as the benefit's value exceeds the money spent.

"Customized opportunity" means an energy efficiency program tailored to an individual natural gas user's needs.

"Deemed savings" means an estimate of natural gas savings for a single unit of an installed energy-efficiency or renewable-energy measure that (1) has been developed from data sources and analytical methods that are widely considered acceptable for the measure and purpose, and (2) will be applied to measures that are deployed in significant numbers in similar ways.

"Demand portfolio" means a collection of energy efficiency programs, or as defined in this subchapter, Demand Programs including fuel switching programs offered or proposed by a natural gas utility; for example, a residential weatherization program and a program to trade tankless water heaters for tank water heaters or a general education program for energy efficiency may be contributors to a demand portfolio.

"Demand portfolio administrator" means the utility employee responsible for supervising the utility's energy efficiency efforts as proposed in compliance with this subchapter.

"Demand Program(s)" means the Energy Efficiency programs offered or proposed by a natural gas utility. Collectively, the Demand Programs make up the company's Demand portfolio.

"Education" means any formal program, training, or activity designed to raise awareness of, and participation in company specific Demand Programs or increase general knowledge concerning energy savings opportunities and efficiency topics. These programs shall include communication efforts designed to reach customers with energy efficiency information through a variety of mediums including but not limited to television, radio, print and web-based media.

"Energy efficiency" means reducing natural gas consumption on the customer's side of the meter while achieving substantially the same level of end-use service.

"Evaluation, measurement, and verification" or "EM&V" means a systematic, objective study conducted periodically to authenticate, assess, and report how well a Demand program is achieving its objectives, including identification and quantification of inputs, outputs, outcomes, and unintended effects.

"EM&V Costs" means the costs associated with performance of studies and activities intended to determine the actual savings and other effects from Demand Programs.

"Free rider" means a program participant who would have implemented the program measure or practice in the absence of the Demand Program. Free riders can be total, in which the participant's activity would have completely replicated the program measure; partial, in which the participant's activity would have partially replicated the program measure; or deferred, in which the participant's activity would have completely replicated the program measure, but at a time after the time the program measure was implemented.

"Fuel switching" means changing from rate regulated natural gas to rate regulated electricity or from rate regulated electricity to rate regulated natural gas for a particular end-use service. It does not include installation of any device that relies primarily on on-site renewable energy, such as, but not limited to, a solar water heater, geothermal heat pump, or biomass gas-powered furnace.

"Goal" means a target to be achieved by a utility's Demand Portfolio. A goal may be expressed in thousand cubic feet, dekatherms, percentage reduction or limitation, and/or another quantifiable measurement approved by the Commission. When determining whether a goal is met, reductions or increases attributable to weather and economic activity will not be counted.

"Gross savings" means the values reported by a gas utility after the Demand Program activities have been completed, but prior to the time an independent, third-party evaluation of the savings is performed. As with projected savings estimates, these values may utilize results of prior evaluations and/or values in technical reference manuals. However, they are adjusted from projected savings estimates by correcting for any known data errors and actual installation rates and may also be adjusted with revised values for factors such as per-unit savings values, operating hours, and savings persistence rates. Gross savings can be indicated as first year, annual demand or energy savings, and/or lifetime energy or demand savings values.

"Hard-to-reach customers" means:

(A) Residential natural gas users who rent their residences from persons other than kin related to the third degree of affinity or consanguinity, trusts operated by and for the benefit of the users, or the users' legal guardians;

(B) Commercial natural gas users who rent their business property from persons other than the users' owners, parent companies, subsidiaries of their parent companies, their own subsidiaries, or trusts operated by and for the benefit of the same;

(C) Residential or commercial natural gas users who traditionally fail to engage in Demand Programs because of one or more barriers beyond those experienced by average residential or commercial customers in a utility's service area.

"Incentive" means a sum of money a utility may be allowed to recover, in addition to program costs and allowed lost net revenues. Incentives shall be based on the utility's verified savings from the Demand Portfolio for the previous program year and shall be calculated as described in 165:23-45-8.

"Inducement" means anything of value offered by a utility to encourage natural gas users or trade allies to engage in a Demand Program approved pursuant to this subchapter.

"Lost net revenue" means income from the retail sale of natural gas forgone by a utility directly resulting from the success of its demand portfolio, less expenses the utility was not required to pay by forgoing the sales. Lost net revenue shall be calculated using verified savings, shall exclude customer service charge revenues (non-volumetric revenues), and shall exclude revenues collected from riders with annual true-ups.

"Low-income customer" means a residential natural gas user who provides proof to a utility that the user has been determined by the appropriate authority to be eligible to receive services through the Oklahoma Department of Commerce Weatherization Assistance Program State Plan, as provided by OAC 150:80; Health Care Authority SoonerCare Choice or fee-for-service programs, as provided by OAC 317:25, 35, and 40; or Department of Human Services Temporary Assistance for Needy Families, State Supplemental Payment, Low Income Home Energy Assistance, Food Stamp, or Refugee Resettlement programs as provided by OAC 340:10, 15, 20, 50, and 60, respectively, or similar program.

"Market potential study" means an evaluation that assesses customer population base lines, customer needs, target customer populations, and how best to address these issues.

"Market transformation" means the strategic process of influencing customer population and trade ally's decision-making that creates lasting change in customer behavior by removing barriers or exploiting opportunities to accelerate adoption of cost-effective energy efficiency as a matter of standard practice.

"Measure" means the equipment, materials, or actions that are installed or used within a Demand Program that results in measurable or verifiable savings; for example, a measure would include caulking around windows or weather stripping around doors to prevent heat loss.

"Natural gas user" means a real property freeholder or leaseholder at a specific location who consumes natural gas at that location, regardless of whether the consumer receives a gas bill directly from a utility.

"Net benefits" equal the difference between total benefits and total costs as calculated for cost-effectiveness. The economic objective of Demand Resource portfolios is to maximize net benefits. A portfolio is cost-effective if it yields positive net benefits.

"Net savings" means the total change in load that is directly attributable to a Demand Program or the Demand Portfolio. This change in energy and/or demand use shall include, implicitly or explicitly, consideration of appropriate factors. These factors shall include free ridership, participant and non-participant spillover and induced market effects.

"Net Source Energy Usage Savings" means the total change in source energy usage that is directly attributable to a Demand Portfolio. This change in source energy usage will reflect the pre-treatment source energy usage of a device or process less the post-treatment source energy usage of a device or process and shall include, implicitly or explicitly, consideration of appropriate factors. These factors shall include free ridership, participant and non-participant spillover and induced market effects.

"Net-to-gross" means a factor representing net program savings divided by gross program savings that is applied to gross program impacts to convert them into net program impacts. The factor shall be made up of a variety of factors that create differences between gross and net savings, and commonly consider the effects of free riders and spillover.

"Program" means an organized set of activities or measures directed toward the common purpose of energy efficiency that a utility undertakes or proposes to undertake to reduce future natural gas usage or growth in natural gas usage; for example, a general offer to assist homeowners in weatherizing their homes is a program.

"Program cost" means the expenditures including expenditures paid to a third-party to deliver a program, incurred by a utility to achieve natural gas savings through Demand Programs. Expenditures made by customers or third parties are not included. Programs costs must be reported in nominal dollars in the year in which they are incurred, regardless of when the savings occur. The utility's Demand Program costs are all Administrative Costs, Education costs, labor, equipment, inducement, marketing, monitoring, measurement and evaluation, and other program delivery expenditures incurred by the utility for operation of the Demand Programs, regardless of whether the costs are expensed or capitalized.

"Program implementer" means the person who puts a Demand Program into practical effect.

"Projected incentives" means the amount of estimated annual incentives calculated at the time the Demand Portfolio is submitted to the Commission for initial approval, or subsequent modification, of the Demand Portfolio.

"Projected savings" means the values reported by a natural gas utility prior to the implementation of the Demand Programs. These are typically estimates of savings prepared for Demand Program and/or Demand Portfolio design or planning purposes. These values are based on pre-program or Demand Portfolio estimates of factors such as per-unit savings values, operating hours, Net-to-Gross ratios, installation rates, and savings persistence rates. These values can be indicated as first year, annual energy savings, and/or lifetime energy values. These values can also be indicted as Gross savings and/or Net savings. Projected savings are reflected in the goal reduction as set in this Subchapter.

"Research and development" means a planned activity aimed at discovering new knowledge with the hope of developing new or improved energy efficiency processes, products, or services and the translation of these research findings into a plan or design for new or improved energy efficiency processes, products, and services.

"Savings" means a reduction in the use of natural gas or rate of growth of natural gas use, as measured in dekatherms or thousand cubic feet.

"Spillover" means the reductions in energy consumption caused by the presence of a Demand Program, beyond the Demand Program-related gross savings of the participants and without financial or technical assistance from the program. Spillover can be applied to participants, consumers directly participating in a Demand Program, and/or non-participants.

"Standard offer" means a Demand Program available to a group of customers or customers generally on the same terms and without customization.

"Trade allies" means contractors, builders, developers, retailers, skilled laborers, service providers, and wholesale distributors who support Demand Programs through sale or installation of goods and services.

"Transportation Customer" means any customer who buys gas on the open market from any provider, and engages a regulated utility's pipeline to transport the gas to the customer's facility.

"Verified savings" means values reported by a natural gas utility after review by an independent third-party evaluator. The third party evaluator shall be chosen by the utility and such costs shall be determined to be a Program cost. These values should reflect all adjustments including corrections for any known data errors and actual installation rates, and should also be adjusted by revised values for known factors such as per-unit savings values, operating hours, savings persistence rates, and net to gross adjustments.

[**Source**: Added at 26 Ok Reg 1859, eff 6-25-09; Amended at 31 Ok Reg 1067, eff 1-1-2017]

165:45-23-4. Demand portfolio submission and implementation

(a) All natural gas utilities under rate regulation of the Commission having more than 25,000 meters in the state of Oklahoma shall propose, at least once every three years, and be responsible for the administration and implementation of a Demand Portfolio of Demand Programs within their service territories. Such proposals shall be made by filing an application with the Commission on or before May 1 of the year the programs will be effective. The application shall describe the Demand Portfolio and contain the following information:

(1) A description of the intent of the Demand Portfolio as a whole;

(2) A description of the intent of each Demand Program;

(3) A description and quantification of the target market of each Demand Program, differentiated by customer sectors;

(4) A base line describing the state of the market that each program is intended to address, taking into account applicable building energy codes and appliance and equipment energy standards;

(5) A description of the barriers to investment in energy efficiency in the absence of each Demand Program and the ways each Demand Program will reduce or eliminate these barriers;

(6) A description of research and public input that contributed to the development of the content of each Demand Program;

(7) A report of the cost-effectiveness of each Demand Program and the Demand Portfolio, including program and measure-level supporting data which shall include, but not be limited to, cost-effectiveness screening assumptions of gross and net energy savings, participation and/or measure unit numbers, inducement levels, measure cost, and other non-inducement program costs;

(8) A detailed description of the derivation of the energy, generation, and transmission and distribution avoided costs, retail cost projections, reserve margins, discount rates, and average and peak line loss assumptions used in the cost-effectiveness calculations;

(9) A description of how each Demand Program is expected to change over its course to reflect expected changes in market penetration, technology, and other market information, as well as lessons learned;

(10) A plan for evaluation, measurement, and verification of performance and results of the Demand Portfolio and each program, including a plan for the use of deemed savings, if applicable, or the use of statistical sampling, if applicable, or the use of metering, where appropriate; provided that costs associated with the EM&V plan shall not exceed five percent (5%) of the total three-year Demand Portfolio budget;

(11) A plan for evaluation of the market effects of each Demand Program or applicable group of programs;
(12) A plan for evaluation of administration and implementation of each Demand Program or applicable group of programs;
(13) A plan for ending a Demand Program, if applicable;
(14) A process for amending a Demand Program;
(15) An annual budget for each Demand Program, providing detail for program costs, and differentiating evaluation, measurement, and verification costs from other program costs;
(16) A report on how the Demand Portfolio is expected to affect rates, sales, average bills and total revenue requirement for each customer sector;
(17) A report on how the Demand Portfolio will meet savings goals that may be in place at the time of filing and or that are otherwise proposed in the filing;
(18) An estimate of the expected savings in natural gas usage, with location information about the source of savings, if savings are not expected to be evenly distributed throughout the utility system;
(19) A detailed explanation of the utility's request for recovery of prudently incurred program costs, recoupment of lost net revenue, and any additional incentives the utility proposes it requires to make the programs workable;
(20) Identification of the Demand Portfolio administrator, including name, job title, business postal address, business electronic mail address, and business telephone number; and

(b) Demand Portfolios shall:
(1) Contain Demand Programs for all customer sectors;
(2) Strike a balance among procuring natural gas savings, educating the public, and transforming markets for energy efficiency;
(3) Include standard offers to customers and trade allies to encourage simple ways to participate, where appropriate;
(4) Contain customized opportunities for energy efficiency among larger customers;
(5) Not include programs or measures that promote fuel switching, with the exception of:
(A) programs or measures that promote renewable technologies such as biomass-derived methane, geothermal, solar and other renewable resources; or
(B) in the event after notice and hearing, such programs or measures are shown to promote the goals of the Commission pursuant to this Subchapter and/or otherwise to be in the public interest;
(6) Have an implementation schedule of no more than three years;
(7) Address opportunities presented by new construction and renovation;
(8) Promote comprehensive energy efficiency in buildings; and
(9) Address programs for low-income customers and hard-to-reach customers to assure proportionate Demand Programs are deployed in these customer groups despite higher barriers to energy efficiency investments. Programs targeted to low-income or hard-to-reach customers may have lower threshold cost-effectiveness results than other programs.

(c) Demand portfolios may:

(1) Include research and development and pilot programs that would lead to effective Demand Programs or other energy end use efficiency for Oklahoma so long as the total budget for such programs does not exceed five percent of the total budget for Demand Programs and the Commission finds the cost-effectiveness for the Demand Portfolio remains sufficient;
(2) Encourage utility cooperation in state, regional and national programs that have the potential to save natural gas in Oklahoma;
(3) Encourage utility cooperation in state, regional and national programs to take advantage of economies of scale, provide consistent mass media messages, or otherwise improve program administration or customer acceptance; and
(4) Encourage utility cooperation in state, regional and national efforts to accelerate the development and improve the enforcement of building energy codes and product efficiency standards.

(d) Natural gas utilities having fewer than 25,000 meters in this state are exempt from filing application requirements in subsections (a) through (c); however, each qualifying natural gas utility shall submit to the director of the Public Utility Division for review, evidence of why it is not economically feasible to file the application requirements in subsections (a) through (c), and shall submit the following as evidence to further the goals of this Subchapter:
(1) A description of the Demand Programs that are economically feasible to implement; and
(2) The target market of each Demand Program.

(e) Transportation customers shall not be subject to Demand Programs and related Program costs implemented pursuant to this Subchapter.

[**Source**: Added at 26 Ok Reg 1859, eff 6-25-09; Amended at 31 Ok Reg 1067, eff 1-1-2017]

165:45-23-5. Commission consideration

(a) In reviewing Demand Portfolios, the Commission will consider:
(1) The quality of the Demand Programs in all their elements relative to their program objectives;
(2) Experience of the program administrator and program implementer, if known, at designing and implementing programs;
(3) The cost-effectiveness for each program and for the Demand Portfolio; individual programs or individual measures for a specific program do not have to be cost-effective if their inclusion is expected to provide for greater comprehensiveness, customer or trade ally participation, or address Hard to Reach Customer participation;
(4) The savings goals;
(5) The availability of programs to all customers;
(6) The degree to which programs include innovative ways of increasing savings, increasing participation in programs, increasing market transformation, increasing customer education, or decreasing the cost to obtain savings or promote participation and include stakeholder interests;

(7) The effect on rates, average customer bills, and total cost of service;
(8) The effect on the environment, to the extent of Commission authority; and
(9) Other evidence the Commission finds relevant.

(b) The Commission will endeavor to issue an order within ninety days of the filing of the application.

(c) Whether a program is cost effective will be determined by the Commission and may be based on the tests found in the California Standard Practice Manual. The California Standard Practice Manual tests are to be used in conjunction with one another and no one test may be used to deem a program to be lacking cost-effectiveness. Results of the Rate Impact Measure Test contained in the California Standard Practice Manual shall also include an estimate of the impact on average customer bills.

(d) A utility's recovery of prudently incurred program costs in rates or riders shall be determined by the Commission on a utility-specific basis; provided that:
(1) Administrative costs shall not exceed ten percent (10%) of program costs;
(2) All program costs should not add more than $1.60 to the residential sector's monthly average customer bill, unless benefits and rationale for exceeding cap can be proven; bill impacts on other classes of customers should be reviewed and adjusted to reflect allocated Demand Program cost recovery; and
(3) Tariffs covering rates or riders for Demand Programs shall be updated to be in compliance with this Subchapter or in accordance with OAC 165:45-1-4(b) and (f).

(e) Programs may be modified by the utility with forty-five days notice to the Commission without prior approval by the Commission under the following conditions:
(1) The program is not terminated earlier than specified in the program; and
(2) The modification does not result in a shift of more than ten percent of the total demand portfolio budget resources away from programs serving any customer sector.

(f) If the Commission receives an objection to the proposed program modification no later than thirty days after receiving the utility's notice, the Commission may, but is not required to, set a hearing before the Commission or an administrative law judge.

[**Source**: Added at 26 Ok Reg 1859, eff 6-25-09; Amended at 31 Ok Reg 1067, eff 1-1-2017]

165:45-23-6. Evaluation, measurement, and verification

(a) Utilities are responsible for timely evaluation, measurement, and verification (EM&V) of their Demand Programs. The EM&V should be conducted by an independent third party evaluator chosen by the utility and cost of such EM&V shall be determined to be a Program Cost.

(b) The intent of the evaluation, measurement, and verification process is:
(1) To provide a reliable calculation of the net savings produced by Demand Programs;
(2) To assess the effects of Demand Programs on the market for energy efficient products and services; and
(3) To assess the effectiveness of the administration and implementation of Demand Programs.

(c) Utilities shall prepare and maintain a program-tracking database.
(d) Each evaluation, measurement, and verification plan for a program will explain the methods that will be applied with an explanation of how those methods will meet the requirements of this rule.
(e) Deemed savings, customer bill analysis, on-site metering, and statistical sampling will be permitted in appropriate applications.
(f) Assumptions with any supporting research about the ratio between gross savings in energy consumption by utility customers and net savings attributable to Demand Programs will be included in the evaluation, measurement, and verification plan.
(g) The evaluation, measurement, and verification process shall produce reports that are fully documented, auditable, and transparent.

[Source: Added at 26 Ok Reg 1859, eff 6-25-09; Amended at 31 Ok Reg 1067, eff 1-1-2017]

165:45-23-7. Reporting

(a) Each utility shall submit an annual report by May 1 of each year on the performance of Demand Portfolio for the preceding program year and cumulative program performance which shall include the information enumerated in this section.
(b) The annual report shall be submitted with Verified savings information in order for PUD to evaluate incentives levels to be recovered from consumers. PUD will provide Company with written notification of incentive levels, confirming or identifying disputed amounts with rationale for dispute by September 1. Any undisputed incentives may be included in recovery according to formula rate or other tariff terms. Any disputed incentives amounts will be resolved during the subsequent formula rate filing or other tariff recovery reviews. True-up mechanisms and recovery for all other Demand Program Costs shall be included with formula rate filings or other tariff recovery mechanisms.
(c) The report shall contain a Demand Portfolio summary reflecting the scale of each program as a part of the Demand Portfolio and will include the following:

(1) The name of Demand Program listed by customer category;
(2) The date program was started or date the Demand Program was revised;
(3) The number of participating customers per Demand Program;
(4) By Demand Program, approved projected energy savings (in decatherms) as approved;
(5) The gross energy savings (in decatherms) and performance of each Demand Program;
(6) The verified energy savings (in decatherms) by Demand Program and methods used to verify;
(7) For Education programs measurements of outreach efforts, including pre-program and post-program results and copies of evaluations, surveys, focus group results, and other measurement techniques used to gauge the effectiveness of education efforts;
(8) The levelized cost per decatherm for the Demand Portfolio, Demand Programs, and by customer sector, including all assumptions used to make the calculation;

(9) The amount of reduced emissions and water consumption experienced by the utility, including all assumptions and calculations details, during the Demand Program period for the current program year;
(10) The Demand Portfolio funding as a percent of total annual gas revenue;
(11) The Demand Portfolio Net source energy savings as a percent of total gas annual usage;
(12) The projected program costs;
(A) These costs should be separated into the following categories to allow review of spending:
(i) Administrative costs;
(ii) Inducements: direct payments and other inducements;
(iii) Education and marketing costs;
(iv) Program delivery costs; and
(v) EM&V costs.
(B) Workpapers to allow review and reconciliation of accounting information:
(i) Utilities shall provide workpapers with working formulas, calculations, and linkages to support all costs;
(ii) General Ledger: A copy of, or access to, the general ledger and subledgers; and
(iii) Comparative Trial Balances: A schedule of, or access to, comparative trial balances detailed by account for the test year and the first preceding year.
(13) The actual program costs;
(A) These costs should be separated into the following categories to allow review of spending;
(i) Administrative costs;
(ii) Inducements: direct payments and other inducements;
(iii) Education and marketing costs;
(iv) Program delivery costs; and
(v) EM&V costs.
(B) Workpapers to allow review and reconciliation of accounting information:
(i) Utilities shall provide workpapers with working formulas, calculations, and linkages to support all costs;
(ii) General Ledger: A copy of, or access to, the general ledger and subledgers; and
(iii) Comparative Trial Balances: A schedule of, or access to, comparative trial balances detailed by account for the test year and the first preceding year.
(14) Projected incentives – including projected cost effectiveness tests;
(15) Actual calculated incentives – including workpapers and working spreadsheets (formulas, calculations, linkages, and assumptions) for updated cost effectiveness tests, in sufficient detail to allow review of cost effectiveness calculations;
(16) The utility's annual growth in metered energy for the previous three years, with a calculation of the average growth rate over that entire period by customer class or major customer class segments;

(17) The most current information available comparing the base line and milestones to be achieved under market transformation programs with actual conditions in the market;
(18) By Demand Program, provide a summary of spending, including the following:
(A) Administrative costs;
(B) Inducements, including direct payments and other inducements;
(C) Education and marketing costs;
(D) Program Delivery Costs; and
(E) EM&V costs.
(19) A statement of any funds that were committed but not spent during the year, by program, with an explanation for non-spending;
(20) A detailed description of each Demand Program reflecting the scale of the program as a part of the Demand Portfolio that includes the following:
(A) Number of customers served by each Demand Program or program category;
(B) Program or program category expenditures;
(C) Verified energy and peak demand savings achieved by the Demand Program or program category, when available; and
(D) A description of proposed changes in the Demand Program plans.
(21) A list of research and development activities included in the Demand Portfolio, their status, and a report on the connection between each activity and effective Demand Program; and
(22) Identification of Demand Program implementers, including names, job titles, business postal addresses, business electronic mail addresses, and business telephone numbers.
(d) After receiving the report, the Commission:
(1) May schedule a hearing about the performance of the programs, the outlook for the future, and other relevant issues and may consider requests from parties for a hearing;
(2) Will endeavor to act on the report within ninety days by accepting the report, rejecting the report, or opening an investigation to inquire further into the report.
(e) The Commission may direct the utility to make brief quarterly or monthly reports including measurements of key metrics and news of any unexpected developments in Demand Program administration, delivery or planning.

[**Source**: Added at 26 Ok Reg 1859, eff 6-25-09; Amended at 31 Ok Reg 1067, eff 1-1-2017]

165:45-23-8. Incentives
(a) Each utility shall be eligible to receive an incentive for successful implementation of their Demand Portfolio if:
(1) The Demand Portfolio achieves a minimum of 80% of the company's goal ratio (Verified savings divided by Projected savings);
(2) and the Demand Portfolio achieves a total resource cost test benefit/cost ratio (TRC:B/CR) that is greater than one; and

(3) No incentive shall be allowed for performance of the Demand Portfolio if the Utility fails to pass all of these threshold measures (OAC 165:45-23-8(a)(1) and (2)).

(b) The Incentive will be calculated as follows:

(1) A maximum incentive of 15 percent of Net Benefits will be paid for achievement of 100 percent (100%) or greater of the Utility's total annual Net Energy Source savings goal.

(A) The goal ratio (Verified savings divided by the Projected savings) must be 80% or greater to receive an incentive.

(B) Incentive for savings achieved between 80 and 100 percent of the savings goal will be determined by multiplying the goal ratio by the maximum incentive percentage.

(2) The Demand Portfolio costs to be included for review of achievement of Demand Portfolio shall include all costs incurred for implementation of Demand Programs including all program costs, education or outreach program costs, Administrative costs, and EM&V costs.

(3) Costs incurred for the implementation or reporting of the Demand Programs which are not directly incurred for a specific program are to be allocated to all Demand Programs and included as part of the Demand Program costs in determining Demand Portfolio cost effectiveness.

(c) The Incentive will be capped at 15 percent of Demand Portfolio costs inclusive of program delivery costs, education, and/or marketing outreach costs, Administrative costs and EM&V costs.

[**Source:** Added at 31 Ok Reg 1067, eff 1-1-2017]

165:45-23-9. Stakeholder process

(a) Each utility shall have, at a minimum semi-annual stakeholder meetings, one of which is to be held within 30 days of the submittal of the Annual Report, as set forth in 165:45-23-7. Notice of such meetings shall be made at least 30 days prior to the date of the stakeholder meeting.

(b) At each meeting the utilities will present their most current data as to savings goal attainment and budget expenditures at the Demand Portfolio, customer sector and Demand Program level. The utility will highlight any Demand Program changes implemented since the previous meeting and any planned changes that will occur prior to the next meeting.

(c) In the years in which a utility plans to file a Demand Portfolio application as required by OAC 165:45-23-4, the Public Utility Division shall use one of the semi-annual stakeholder meetings to obtain stakeholder feedback on the proposed application.

[**Source:** Added at 31 Ok Reg 1067, eff 1-1-2017]