199—35.5(476) Energy efficiency and demand response plan requirements.

35.5(1) Each electric and natural gas utility shall file with the commission an energy efficiency plan, and each electric utility shall file a demand response plan.

35.5(2) The utility's energy efficiency and demand response plans shall include testimony, exhibits, and workpapers, including Microsoft Excel or similar software versions of exhibits and workpapers.

35.5(3) A utility's plan shall include a range of programs that address all customer classes across the utility's Iowa jurisdictional territory and include a program for qualified low-income residential customers, including a cooperative program with any community action agency, as defined and listed on the Iowa department of health and human services website, within the utility's service area to implement countywide or communitywide energy efficiency programs for qualified low-income customers. The utility shall consider including in the utility's plan a program for tree-planting, educational programming, and assessments of consumers' needs for information to make effective choices regarding energy use and energy efficiency.

35.5(4) The following information shall be provided by the utility with the utility's energy efficiency and demand response plan:

a. A summary of the energy efficiency and demand response plans and results of the assessment of potential written in a nontechnical style for the benefit of the general public.

b. The assessment of potential study.

c. Cost-effectiveness test analysis.

(1) The utility shall analyze cost-effectiveness for the plan as a whole and for each proposed program, using the total resource cost, societal cost, utility cost, and ratepayer impact measure and participant tests. If the utility uses a test other than the societal cost test as the criterion for determining cost-effectiveness of utility implementation of energy efficiency measures, the utility shall describe and justify the utility's use of the alternative test or combination of tests and compare the resulting impacts with the impacts from the societal cost test. The utility shall describe and justify the level or levels of cost-effectiveness, if greater or less than a cost-effectiveness ratio of 1.0, to be used as a threshold for determining cost-effectiveness of programs. The utility's threshold of cost-effectiveness for the utility's plan as a whole shall be a cost-effectiveness ratio of 1.0 or greater.

(2) The utility's analyses shall use inputs or factors reasonably expected to influence cost-effective implementation of programs, including escalation rates and avoided costs for each cost and benefit component of the cost-effectiveness test, to reflect changes over the useful lives of the programs.

(3) The utility shall provide the analyses, assumptions, inputs, and results of cost-effectiveness tests, including the cost-effectiveness ratios and net benefits, for the plans as a whole and for each program. Low-income programs, tree-planting programs, educational programs, and assessments of consumers' needs for information to make effective choices regarding energy use and energy efficiency need not be tested for cost-effectiveness unless the utility wishes to present the results of cost-effectiveness tests for informational purposes.

d. Descriptions of each program. If a proposed program is identical to an existing program, the utility may reference the program description currently in effect. A description of each proposed program shall include:

(1) The name of the program.

(2) The customers the program targets.

(3) The energy efficiency or demand response measures promoted by the program.

(4) The proposed utility promotional techniques, including the rebates or incentives offered through the program.

(5) The proposed rates of program participation or implementation of measures, including both eligible and estimated actual participants.

e. The gross and net estimated annual energy and demand savings for the plan and each program for each year of the program that accounts for free riders, take-back effects, spillover (free drivers), market effects, and persistence of energy savings.

f. The budget for the plan and for each program for each year of implementation or for each of the next five years of implementation, whichever is less, itemized by proposed costs and consistent with the accounting plan required pursuant to subrule 35.9(1). Cost categories for the plan and program budgets include overhead and incentives as described herein, and the cost categories shall be further described by the following subcategories: classifications of persons working on energy efficiency and demand response programs, full-time equivalents, dollar amount of labor costs, and the name of outside firm(s) employed and a description of service(s) to be provided.

(1) Overhead consists of:

1. Planning and design costs, which include internal and third-party expenses associated with program development, design for new programs, modifications to existing programs, and the assessment of potential.

2. Administrative costs, which include internal and third-party expenses associated with program implementation and support functions, such as fully loaded utility labor costs, office supplies and technology costs associated with program operations and delivery, program implementation costs, and labor costs for vendors required for successful operation and implementation of programs.

3. Advertising and promotional costs, which include internal and third-party labor and materials expenses associated with program-specific marketing and training and demonstration aimed at promoting energy efficiency awareness or the programs included in a utility's plan. Advertising that is part of an approved energy efficiency or demand response plan is deemed to be advertising required by the commission for purposes of Iowa Code section 476.18(3).

4. Monitoring and evaluation costs, which include internal and third-party expenses associated with ongoing program review; prepayment verification inspections; and evaluation, measurement, and verification required to be completed at least once during the five-year plan.

5. Education costs, which include internal and third-party labor and material expenses associated with program-specific or general energy efficiency education.

6. Miscellaneous costs, which are all other costs related to the implementation of the plan that are not attributable to any other cost category.

(2) Incentives consist of:

1. Customer incentives, which are utility contributions provided to participants, such as rebates, direct-install measures, energy audits, energy efficiency kits, and low-income weatherization. This includes nonrebate contributions to participants, such as payments to dealers, rate credits, and bill credits.

2. Equipment costs, which include program-specific costs associated with hardware purchased by the utility and given to customers to facilitate the customer's participation in the program.

3. Installation costs, which include internal and third-party labor associated with installation or replacement of equipment provided to participants, such as the installation of direct-install measures or load control devices.

g. A description of a pilot project as a program, if the pilot project is justified by the utility. Pilot projects are expected to explore areas of innovative or unproven approaches and include proposed evaluation procedures.

h. The rate impacts and average bill impacts, by customer class, resulting from the plan.

i. The utility's forecasted electric, natural gas, or electric and natural gas annual Iowa retail rate revenue for each of the five plan years, identifying all adjustments and eliminations to the utility's revenue forecasts and the Federal Energy Regulatory Commission (FERC) accounts used to develop the utility's forecasts.

j. A monitoring and evaluation plan describing how the utility proposes to monitor and evaluate the implementation of the utility's proposed programs, including how the utility will accumulate and validate the information needed to measure the plan's performance against the standards, a timeline that outlines each phase of the monitoring and evaluation plan, and a proposed format for monitoring reports and a description of how annual results will be reported to the commission on a detailed, accurate and timely basis.

k. A summary of collaborative efforts and a summary of collaboration participants' suggestions, utility responses to the suggestions, and specific reasons for incorporating or declining to incorporate the suggestions in the utility's energy efficiency or demand response plans.

l. These additional requirements for electric utilities:

(1) Load forecast. Information specifying forecasted demand and energy use on a calendar-year basis, which shall include:

1. A statement, in numerical terms, of the utility's current 20-year forecasts, including summer and winter peak demand reserve margins and annual energy requirements that account for the effects to date of current and ongoing utility energy efficiency programs but not the effects of the proposed programs in paragraph 35.5(4)*"d."*

2. The date and amount of the utility's highest peak demand within the past five years, stated on both an actual and a weather-normalized basis. The utility shall include an explanation of the weather-normalization procedure.

3. A comparison of the forecasts made for each of the previous five years to the actual and weather-normalized demand in each of the previous five years.

4. An explanation of all significant methods and data used, as well as assumptions made, in the current 20-year forecast, including all forecasts of variables used in its demand and energy forecasts and separate identification of all sources of variables used, such as implicit price deflator, electricity prices by customer class, gross domestic product, sales by customer class, number of customers by class, fuel price forecasts for each fuel type, and other inputs.

5. A statement of the margin of error for each assumption or forecast.

6. An explanation of the results of sensitivity analyses performed, including a specific statement of the degree of sensitivity of estimated need for capacity to potential errors in assumptions, forecasts, and data. The utility may present the results and an explanation of other methods of assessing forecast uncertainty.

(2) Class load data. Load data for each class of customer that is served under a separate rate schedule or is identified as a separate customer class and accounts for 10 percent or more of the utility's demand in kW at the time of the monthly system peak for every month in the year. If those figures are not available, the data shall be provided for each class of customer that accounts for 10 percent of the utility's electric sales in kWh for any month in the reporting period. The data shall be based on a sample metering of customers that is designed to achieve a statistically expected accuracy of plus or minus 10 percent at the 90 percent confidence level for loads during the yearly system peak hour(s). These data must appear in all filings, except as provided for in numbered paragraph 35.5(4)*"l"*(2)"3."

1. The following information shall be provided for each month of the previous year:

- Total system class maximum demand (in kW), number of customers in the class, and system class sales (in kWh);
- Jurisdictional class contribution (in kW) to the monthly maximum system coincident demand as allocated to jurisdiction;
- Total class contribution (in kW) to the monthly maximum system coincident demand, if not previously reported;
- Total system class maximum demand (in kW) allocated to jurisdiction, if not previously reported; and
- Hourly total system class loads for a typical weekday, a typical weekend day, the day of the class maximum demand, and the day of the system peak.

2. The company shall file an explanation, with all supporting workpapers and source documents, as to how class maximum demand and class contribution to the maximum system coincident demand were allocated to jurisdiction.

3. The load data for each class of customer described above may be gathered by a multijurisdictional utility on a uniform integrated system basis rather than on a jurisdictional basis. Adjustments for substantive and unique jurisdictional characteristics, if any, may be proposed. The load data for each class of customer shall be collected continuously and filed annually, except for the period associated with necessary interruptions during any year to modify existing or implement new data collection methods. Data filed for the period of interruption shall be estimated. An explanation of the estimation technique shall be filed with the data. To the extent consistent with sound sampling and the required accuracy standards, an electric public utility is not required to annually change the customers being sampled.

(3) Existing capacity and firm commitments. Information specifying the existing generating capacity and firm commitments to provide service. The utility shall include in its filing a copy of its most recent load and capability report submitted to Midcontinent Independent System Operator, Inc. (MISO).

1. For each generating unit owned or leased by the utility, in whole or in part, the energy efficiency and demand response plan shall include the following information:

● Both summer and winter net generating capability ratings as reported to the North American Electric Reliability Corporation (NERC).

● The estimated remaining time before the unit will be retired or require life extension.

2. For each commitment to own or lease future generating firm capacity, the plan shall include the following information:

● The type of generating capacity.

● The anticipated in-service year of the capacity.

● The anticipated life of the generating capacity.

● Both summer and winter net generating capability ratings as reported to the NERC.

3. For each capacity purchase commitment that is for a period of six months or longer, the plan shall include the following information:

● The entity with which commitments have been made and the time periods for each commitment.

● The capacity levels in each year for the commitment.

4. For each capacity sale commitment that is for a period of six months or longer, the plan shall include the following information:

● The entity with which a commitment has been made and the time periods for the commitment.

● The capacity levels in each year.

● The capacity payments to be received per kW per year in each year.

● The energy payments to be received per kWh per year.

● Any other payment to be received by the utility in each year.

(4) Capacity surpluses and shortfalls. Information identifying projected capacity surpluses and shortfalls over the 20-year planning horizon shall include:

1. A numerical and graphical representation of the utility's 20-year planning horizon comparing forecasted demand in each year from subparagraph 35.5(4)*"l"*(1) to committed capacity in each year from numbered paragraphs 35.5(4)*"l"*(3)"1" to "4." Forecasted peak demand shall include reserve requirements.

2. For each year of the 20-year planning horizon, the plan shall list in megawatts (MW) the amount by which committed capacity either exceeds or falls below the forecasted demand.

(5) Capacity outside the utility's system. Information about capacity outside of the utility's system that could meet the utility's future needs, including but not limited to cogeneration and independent power producers, expected to be available to the utility during each of the 20 years in the planning horizon. The utility shall include in the utility's filing a copy of its most recent load and capability report submitted to MISO.

(6) Future supply options and costs. Information about future supply options and their costs identified by the utility as the most effective means of satisfying all projected capacity shortfalls in the 20-year planning horizon in subparagraph 35.5(4)*"l"*(4), which shall include:

1. The following information that describes each future supply option as applicable:

● The anticipated year the supply option would be needed.

● The anticipated type of supply option, by fuel.

● The anticipated net capacity of the supply option.

2. The utility shall use the actual capacity cost of any capacity purchase identified in numbered paragraph 35.5(4)*"l"*(6)"1" and shall provide the anticipated annual cost per net kW per year.

3. The utility shall use the installed cost of a combustion turbine as a proxy for the capacity cost of any power plant identified in numbered paragraph 35.5(4)*"l"*(6)"1." For the first power plant option specified in numbered paragraph 35.5(4)*"l"*(6)"1," the following information shall be provided:

● The anticipated life.

● The anticipated total capital costs per net kW, including allowance for funds used during construction (AFUDC) if applicable.

● The anticipated revenue requirement of the capital costs per net kW per year.

● The anticipated revenue requirement of the annual fixed operations and maintenance costs, including property taxes, per net kW for each year of the 20-year planning horizon.

● The anticipated net present value of the revenue requirements per net kW.

● The anticipated revenue requirement per net kW per year calculated by utilization of an economic carrying charge.

● The after-tax discount rate used to calculate the revenue requirement per net kW per year over the life of the supply option.

● Adjustment rates (for example, inflation or escalation rates) used to derive each future cost in numbered paragraph 35.5(4)*"l"*(6)"3."

4. The capacity costs of the new supply options allocated to costing periods. The utility shall describe its method of allocating capacity costs to costing periods. The utility shall specify the hours, days, and weeks that constitute the utility's costing periods. For each supply option identified in numbered paragraph 35.5(4)*"l"*(6)"1," the plan shall include:

● The anticipated annual cost per net kW per year of capacity purchases from numbered paragraph 35.5(4)*"l"*(6)"2" allocated to each costing period if each new supply option is the highest cost supply option in that year.

● The anticipated total revenue requirement per net kW per year from numbered paragraph 35.5(4)*"l"*(6)"3" allocated to each costing period if each new supply option is the highest cost supply option in that year.

(7) Avoided capacity and energy costs. Avoided capacity costs shall be based on the future supply option with the highest value for each year in the 20-year planning horizon identified in subparagraph 35.5(4)*"l"*(6). Avoided energy costs shall be based on the marginal costs of the utility's generating units or purchases. The utility shall use the same costing periods identified in numbered paragraph 35.5(4)*"l"*(6)"2" when calculating avoided capacity and energy costs. A party may submit, and the commission shall consider, avoided capacity and energy costs derived by an alternative method. A party submitting alternative avoided costs shall also submit an explanation of the alternative method.

1. Avoided capacity costs. Calculations of avoided capacity costs in each costing period shall be based on the following formula:

AVOIDED CAPACITY COST = C × (1 + RM) × (1 + DLF) × (1 + EF)

C (capacity) is the greater of NC or RC.

NC (new capacity) is the value of future capacity purchase costs or future capacity costs expressed in dollars per net kW per year of the utility's new supply options from numbered paragraphs 35.5(4)*"l"*(6)"2" and "3" in each costing period.

RC (resalable capacity) is the value of existing capacity expressed in dollars per net kW per year that could be sold to other parties in each costing period.

RM (reserve margin) is the generation reserve margin criterion adopted by the utility.

DLF (demand loss factor) is the system demand loss factor expressed as a fraction of the net power generated, purchased, or interchanged in each costing period. For example, the peak system demand loss factor would be equal to peak system power loss (in MW) divided by the net system peak load (in MW) for each costing period.

EF (externality factor) is a 10 percent factor applied to avoided capacity costs in each costing period to account for societal costs of supplying energy. In addition, the utility may propose a different externality factor but must document the factor's accuracy.

2. Avoided energy costs. Calculations of avoided energy costs in each costing period shall be based on the following formula:

AVOIDED ENERGY COSTS = MEC × (1 + ELF) × (1 + EF)

MEC (marginal energy cost) is the marginal energy cost expressed in dollars per kWh, inclusive of variable operations and maintenance costs, for electricity in each costing period.

ELF (system energy loss factor) is the system energy loss factor expressed as a fraction of net energy generated, purchased, or interchanged in each costing period.

EF (externality factor) is a 10 percent factor applied to avoided energy costs in each costing period to account for societal costs of supplying energy. In addition, the utility may propose a different externality factor but must submit documentation of the factor's accuracy.

m. These additional requirements for natural gas utilities:

(1) Forecast of demand and transportation volumes. Information specifying the natural gas utility's demand and transportation volume forecasts, which includes:

1. A statement in numerical terms of the utility's current 12-month and five-year forecasts of total annual throughput and peak day demand, including reserve margin, based on the purchased gas adjustment (PGA) year by customer class, including the effects to date of current and ongoing utility energy efficiency programs but not including the effects of the proposed energy efficiency programs in paragraph 35.5(4) *"d."*

2. A statement in numerical terms of the utility's highest peak day demand and annual throughput for the past five years by customer class.

3. A comparison of the forecasts made for the preceding five years to the actual and weather-normalized peak day demand and annual throughput by customer class, including an explanation of the weather-normalization procedure.

4. A forecast of the utility's demand for transportation volume for both peak day demand and annual throughput for each of the next five years.

5. The existing contract deliverability by supplier, contract, and rate schedule for the length of each contract.

6. An explanation of all significant methods and data used, as well as assumptions made, in the current five-year forecast(s). The utility shall file all forecasts of variables used in the utility's demand and energy forecasts. If variables are not forecasted, the utility shall indicate all sources of variable inputs.

7. A statement of the margin of error for each assumption or forecast.

8. An explanation of the results of the sensitivity analysis performed by the utility, including a specific statement of the degree of sensitivity of estimated need for capacity to potential errors in assumptions, forecasts, and data.

(2) Capacity surpluses and shortfalls. Information identifying projected capacity surpluses and shortfalls over the five-year planning horizon, which includes a numerical and graphical representation of the utility's five-year planning horizon comparing forecasted peak day demand in each year from numbered paragraph 35.5(4)*"m"*(1)"1" to the total of existing contract deliverability, from numbered paragraph 35.5(4)*"m"*(1)"5." The comparison shall list in dth or Mcf any amount for any year that contract deliverability falls below the forecast of peak day demand. Forecasted peak day demand shall include reserve margin.

(3) Supply options. Information about new supply options identified by the utility as the most effective means of satisfying all projected capacity shortfall in the 12-month and five-year planning horizons in subparagraph 35.5(4)*"m"*(2). For each supply option identified, the plan shall include:

1. The year the option would be needed.
2. The type of option.
3. The net peak day capacity.
4. The estimated future capacity costs per dth or Mcf of peak day demand of the options.
5. The estimated future energy costs per dth or Mcf of each option in current dollars.
6. A description of the method used to estimate future costs.

(4) Natural gas avoided capacity and energy costs. Information regarding avoided costs shall specify the days and weeks that constitute the utility's peak and off-peak periods. Avoided costs shall be calculated for the peak and off-peak periods and adjusted for inflation to derive an annual avoided cost over a 20-year period. In addition, all parties may submit information specifying the hours, days, and weeks that constitute alternative costing periods. A party may submit, and the commission shall consider, alternative avoided capacity and energy costs derived by an alternative method. A party submitting avoided cost methodology shall also submit an explanation of the alternative method.

1. Avoided capacity costs. Calculations of avoided capacity costs in the peak and off-peak periods shall be based on the following formula:

AVOIDED CAPACITY COSTS = [(D + OC) × (1 + RM)] × (1 + EF)

D (demand) is the greater of CD or FD.

CD (current demand cost) is the utility's average demand cost expressed in dollars per dth or Mcf during peak and off-peak periods.

FD (future demand cost) is the utility's average future demand cost over the 20-year period expressed in dollars per dth or Mcf when supplying natural gas during peak and off-peak periods.

OC (other cost) is the value of any other costs per dth or Mcf related to the acquisition of natural gas supply or transportation by the utility over the 20-year period in the peak and off-peak periods.

RM (reserve margin) is the reserve margin adopted by the utility.

EF (externality factor) is a 7.5 percent factor applied to avoided capacity costs in the peak and off-peak periods to account for societal costs of supplying energy. In addition, the utility may propose a different externality factor but must submit documentation of the factor's accuracy.

2. Avoided energy costs. Calculations of avoided energy costs in the peak and off-peak periods on a seasonal basis shall be based on the following formula:

AVOIDED ENERGY COSTS = (E + VOM) × (1 + EF)

E (energy costs) are the greater of ME or FE.

ME (current marginal energy costs) are the utility's current marginal energy costs expressed in dollars per dth or Mcf during peak and off-peak periods.

FE (future energy costs) are the utility's average future energy costs over the 20-year period expressed in dollars per dth or Mcf during peak and off-peak periods.

VOM (variable operations and maintenance costs) are the utility's average variable operations and maintenance costs over the 20-year period expressed in dollars per dth or Mcf during peak and off-peak periods.

EF (externality factor) is a 7.5 percent factor applied to avoided energy costs in the peak and off-peak periods to account for societal costs of supplying energy. In addition, the utility may propose a different externality factor but must submit documentation of the factor's accuracy.

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