UTILITIES DIVISION[199]

Regulatory Analysis

Notice of Intended Action to be published: Iowa Administrative Code 199—Chapter 35
"Energy Efficiency and Demand Response Planning and Reporting for
Rate-Regulated Natural Gas and Electric Utilities"

Iowa Code section(s) or chapter(s) authorizing rulemaking: 476.2 and 476.6(15)
State or federal law(s) implemented by the rulemaking: Iowa Code section 476.6

Public Hearing

A public hearing at which persons may present their views orally or in writing will be held as follows:

July 17, 2024 2 p.m.	Board Hearing Room 1375 East Court Avenue Des Moines, Iowa

Public Comment

Any interested person may submit written comments concerning this Regulatory Analysis. Written comments in response to this Regulatory Analysis must be received by the Utilities Board no later than 4:30 p.m. on the date of the public hearing. Comments should be directed to:

IT Support
Iowa Utilities Board
Phone: 515.725.7300
Email: ITsupport@iub.iowa.gov

Purpose and Summary

The purpose of this proposed rulemaking is to explain the procedures governing energy efficiency and demand response proceedings.

Analysis of Impact

1. Persons affected by the proposed rulemaking:

- Classes of persons that will bear the costs of the proposed rulemaking:

The proposed rules apply to rate-regulated natural gas and electric utilities that are required by the Iowa Code to file five-year energy efficiency plans and demand response plans for review and approval by the Board.

- Classes of persons that will benefit from the proposed rulemaking:

The proposed rules benefit rate-regulated natural gas and electric utilities and other parties that wish to participate in energy efficiency and demand response proceedings.

2. Impact of the proposed rulemaking, economic or otherwise, including the nature and amount of all the different kinds of costs that would be incurred:

- Quantitative description of impact:

By describing and detailing the rules governing such proceedings, these proposed rules are intended to assist rate-regulated natural gas and electric utilities and members of the public who wish to participate in energy efficiency and demand response proceedings. The rules are further intended to ensure that such proceedings are fairly and efficiently conducted. While these proceedings may result in costs to rate-regulated natural gas and electric utilities and participating members of the public, those costs are more directly caused by the Iowa Code provisions that require the energy efficiency and demand response proceedings. The proposed rules in Chapter 35 are intended to assist in minimizing the costs and time spent participating in such proceedings.

- Qualitative description of impact:

Proposed Chapter 35 assists rate-regulated natural gas and electric utilities and members of the public who wish to participate in energy efficiency and demand response proceedings. The proposed rules detail proceeding expectations and procedures.

3. Costs to the State:

- Implementation and enforcement costs borne by the agency or any other agency:

Because proposed Chapter 35 only provides the framework for energy efficiency and demand response proceedings, the rules are not viewed as directly causing costs to the Board; rather, the Board costs associated with such proceedings are more directly caused by Iowa Code section 476.6, which requires the energy efficiency and demand response proceedings.

- Anticipated effect on state revenues:

There is no anticipated effect on state revenues.

4. Comparison of the costs and benefits of the proposed rulemaking to the costs and benefits of inaction:

As discussed in previous responses, because proposed Chapter 35 imposes no direct costs on the public, including rate-regulated natural gas and electric utilities, or the Board (or any other agency), and because the public benefits from the availability of the information contained in Chapter 35, the benefits of providing the information outweigh the cost. Inaction is not advised because the public would not be aware of what was needed to fully participate in energy efficiency and demand response proceedings.

5. Determination whether less costly methods or less intrusive methods exist for achieving the purpose of the proposed rulemaking:

Because proposed Chapter 35 imposes no direct costs, the Board does not believe there is a less costly or intrusive method.

6. Alternative methods considered by the agency:

- Description of any alternative methods that were seriously considered by the agency:

The Board considered inaction.

- Reasons why alternative methods were rejected in favor of the proposed rulemaking:

As stated above, inaction is not advisable because there is value in rules that inform the public of the procedures governing energy efficiency and demand response proceedings.

Small Business Impact

If the rulemaking will have a substantial impact on small business, include a discussion of whether it would be feasible and practicable to do any of the following to reduce the impact of the rulemaking on small business:

- Establish less stringent compliance or reporting requirements in the rulemaking for small business.
- Establish less stringent schedules or deadlines in the rulemaking for compliance or reporting requirements for small business.
- Consolidate or simplify the rulemaking's compliance or reporting requirements for small business.
- Establish performance standards to replace design or operational standards in the rulemaking for small business.
- Exempt small business from any or all requirements of the rulemaking.

If legal and feasible, how does the rulemaking use a method discussed above to reduce the substantial impact on small business?

The agency does not believe proposed Chapter 35 has an adverse effect on small business.

Text of Proposed Rulemaking

ITEM 1. Rescind 199—Chapter 35 and adopt the following **new** chapter in lieu thereof:

CHAPTER 35
ENERGY EFFICIENCY AND DEMAND RESPONSE PLANNING AND REPORTING FOR RATE-REGULATED NATURAL GAS AND ELECTRIC UTILITIES

199—35.1(476) Authority and purpose. These rules are intended to implement Iowa Code sections 476.6(13) and 476.6(15) relating to the energy efficiency and demand response plans and reports filed by rate-regulated natural gas and

electric utilities. The purpose of these rules is to establish requirements for energy efficiency and demand response plans, modifications, prudence reviews, and cost-recovery tariffs.

199—35.2(476) Definitions. Except where otherwise specifically defined by law:

"Annual Iowa retail rate revenue" means the utility's expected revenue forecast based on customer growth rate, usage per customer, volumes, margin rate, customer charge rate, and the cost of generation or fuel.

"Assessment of potential" means development of cost-effective energy and capacity savings available from actual and projected customer usage by applying commercially available technology and improved operating practices to energy-using equipment and buildings and considering market factors, including but not limited to the effects of rate impacts, the need to capture lost opportunities, the nonenergy benefits of measures, and the strategic value of energy efficiency and demand response to the utility.

"Avoided cost" means the cost the utility would have to pay to provide energy and capacity from alternative sources of supply available to utilities as calculated pursuant to subparagraphs 35.5(4)*"l"*(7) and 35.5(4)*"m"*(4).

"Cost-effectiveness tests" means one of the five acceptable economic tests used to compare the present value of applicable benefits to the present value of applicable costs of an energy efficiency or demand response program or plan. The tests are the participant cost test, the ratepayer impact measure test, the societal cost test, the total resource cost test, and the utility cost test. A program or plan passes a cost-effectiveness test if the cost-effectiveness ratio is equal to or greater than one.

"Customer incentive" means an amount or amounts provided to or on behalf of customers for the purpose of having customers participate in energy efficiency programs. Customer incentives do not include the cost of information provided by the utility, nor do customer incentives include customers' bill reductions associated with reduced energy usage due to the implementation of energy efficiency programs. For the purposes of energy efficiency pricing strategies, "incentive" means the difference between a customer's bill on an energy efficiency customized rate and the customer's bill on a traditional rate considering factors such as the elasticity of demand.

"Demand response" means changes in a customer's consumption pattern in response to changes in the price of electricity over time, or in response to incentive payments to induce reduced consumption during periods of high wholesale prices or when system reliability is jeopardized.

"Economic potential" means the energy and capacity savings that result in future years when measures are adopted or applied by customers at the time it is economical to do so. For purposes of this chapter, economic potential may be determined by comparing the utility's avoided cost savings to the incremental cost of the measure.

"Energy efficiency measures" means activities on the customers' side of the meter that reduce customers' energy use or demand, including but not limited to end-use efficiency improvements or pricing strategies.

"Energy savings performance standards" means those standards that are cost-effectively achieved, with the exception of programs for qualified low-income persons, tree-planting programs, educational programs, and assessments of consumers' needs for information to make effective choices regarding energy use and energy efficiency, and includes the annual capacity savings stated either in kilowatt per day (kW/day), in dekatherm per day (dth/day), or in thousand cubic feet per day (Mcf/day) and the annual energy savings stated in either kilowatt hour (kWh), dth, or Mcf.

"Free riders" means program participants who would have implemented energy efficiency measures or practices even without the program.

"Marginal energy cost" means the cost associated with supplying the next Mcf or dth of natural gas for a natural gas utility and the energy or fuel cost associated with generating or purchasing the next kWh of electricity for an electric utility.

"Market effects" means a change in the structure of a market or the behavior of participants in a market that is reflective of an increase (or decrease) in the adoption of energy-efficient products, services, or practices and is related to market intervention(s) (e.g., programs).

"Net benefits" means the present value of benefits less the present value of costs as defined in the cost-effectiveness test.

"Nonenergy benefits" means the many and diverse benefits produced by energy efficiency, in addition to energy and demand savings. The beneficiaries of these benefits can be utility systems, participants, and society.

"Participant cost test" means an economic test used to compare the present value of benefits to the present value of costs over the useful life of an energy efficiency or demand response measure or program from the participant's perspective. Present values are calculated using a discount rate appropriate to the class of customers to which the energy efficiency or demand response measure or program is targeted. Benefits are the sum of the present values of the customers' bill reductions, tax credits, nonenergy benefits and customer incentives for each year of the useful life of an energy efficiency or demand response measure or program. Costs are the sum of present values of the customer participation costs (including initial

capital costs, ongoing operations and maintenance costs, removal costs less a salvage value of existing equipment, and the value of the customer's time in arranging installation, if significant) and any resulting bill increases for each year of the useful life of the measure or program. The calculation of bill increases and decreases must account for any time-differentiated rates to the customer or class of customers being analyzed.

"Persistence of energy savings" means the savings due to changed operating hours, human behavior, interactive factors, and the degradation in equipment efficiency over the life of the measure compared to the baseline.

"Process-oriented industrial assessment" means an analysis that promotes the adoption of energy efficiency measures by examining the facilities, operations, and equipment of an industrial customer in which energy efficiency opportunities may be embedded.

"Ratepayer impact measure test" means an economic test used to compare the present value of the benefits to the present value of the costs over the useful life of an energy efficiency or demand response measure or program from a rate level or utility bill perspective. Present values are calculated using the utility's discount rate. Benefits are the sum of the present values of utility avoided capacity and energy costs (excluding the externality factor) and any revenue gains due to the energy efficiency or demand response measure or program for each year of the useful life of the measure or program. Costs are the sum of the present values of utility increased supply costs, revenue losses due to the energy efficiency or demand response measures, utility program costs, and customer incentives for each year of the useful life of the measure or program. The calculation of utility avoided capacity and energy, increased utility supply costs, and revenue gains and losses must use the utility costing periods.

"Societal cost test" means an economic test used to compare the present value of the benefits to the present value of the costs over the useful life of an energy efficiency or demand response measure or program from a societal perspective. Present values are calculated using a 12-month average of the 10-year and 30-year Treasury Bond rate as the discount rate. The average is calculated using the most recent 12 months at the time the utility calculates its cost-effectiveness tests for its energy efficiency or demand response plan. Benefits are the sum of the present values of the utility avoided supply; nonenergy benefits; and energy costs, including the effects of externalities. Costs are the sum of the present values of utility program costs (excluding customer incentives), participant costs, and any increased utility supply costs for each year of the useful life of the measure or program. The calculation of utility avoided capacity and energy and increased utility supply costs must use the utility costing periods.

"Spillover (free drivers)" means the reduction in energy consumption or demand, or the reduction in both, caused by the presence of an energy efficiency or demand response program, beyond the program-related gross savings of the participants and without financial or technical assistance from the program. The term "free drivers" may be used for individuals who have spillover effects.

"Take-back effect" means a tendency to increase energy use in a facility, or for an appliance, as a result of increased efficiency of energy use. For example, a customer's installation of high-efficiency light bulbs and the subsequent longer operation of lights constitutes "taking back" some of the energy otherwise saved by the efficient lighting.

"Total resource cost test" means an economic test used to compare the present value of the benefits to the present value of the costs over the useful life of an energy efficiency or demand response measure or program from a resource perspective. Present values are calculated using a 12-month average of the 10-year and 30-year Treasury Bond rate as the discount rate. The average is calculated using the most recent 12 months at the time the utility calculates its cost-effectiveness tests for its energy efficiency or demand response plan. Benefits are the sum of the present values of the utility avoided supply, energy costs, nonenergy benefits, and federal tax credits. Costs are the sum of the present values of utility program costs (excluding customer incentives), participant costs, and any increased utility supply costs for each year of the useful life of the measure or program. The calculation of utility avoided capacity and energy and increased utility supply costs must use the utility costing periods.

"Useful life" means the number of years an energy efficiency measure will produce benefits.

"Utility cost test" means an economic test used to compare the present value of the benefits to the present value of the costs over the useful life of an energy efficiency or demand response measure or program from the utility revenue requirement perspective. Present values are calculated using the utility's discount rate. Benefits are the sum of the present values of each year's utility avoided capacity, nonenergy benefits, and energy costs (excluding the externality factor) over the useful life of the measure or program. Costs are the sum of the present values of the utility's program costs, customer incentives, and any increased utility supply costs for each year of the useful life of the measure or program. The calculation of utility avoided capacity and energy and increased utility supply costs must use the utility costing periods.

199—35.3(476) Energy efficiency and demand response plan filing.

35.3(1) Each electric and natural gas utility shall file a five-year energy efficiency plan. Each electric utility shall file a five-year demand response plan. Combination electric and natural gas utilities may file combined assessments of potential and energy efficiency and demand response plans but separately specify which energy efficiency programs and costs are attributable to the electric operation, which are attributable to the natural gas operation, and which are attributable to both. If a combination utility files separate plans, the board may consolidate the plans for purposes of review and hearing.

35.3(2) Written notice of the energy efficiency and demand response plans.

a. Each electric and natural gas utility shall:

(1) Deliver a written notice of its plan filing to all affected customers no more than 62 days prior to the filing of its energy efficiency and demand response plans.

(2) File the written notice with the board for approval not less than 45 days prior to the delivery of the proposed notification to affected customers.

b. Additional information not related to the energy efficiency and demand response plans shall be kept to a minimum and not distract from the required content.

c. The form of the notice, once approved by the board, shall not be altered except to include the rate and bill impact dollars and percentages. The type size and quality shall be easily legible. The notice shall, at a minimum, include the following elements:

(1) A statement that the utility will be filing energy efficiency and demand response plans with the board.

(2) A brief identification of the proposed energy efficiency and demand response programs, a description of benefits and savings associated with the energy efficiency and demand response plans, and the estimated annual cost of the proposed energy efficiency and demand response programs during the five-year budget time frame.

(3) The estimated annual rate and bill impacts of the proposed energy efficiency and demand response plans on each class of customer, and the estimated annual jurisdictional rate impact for each major customer grouping in dollars and as a percentage, with the proposed actual increases to be filed at the time of notice to customers. The utility may represent the estimated annual rate and bill impact dollars and percentages with blank spaces; however, the board may require the utility to submit additional information necessary for review of the proposed form of notice. A copy of the notice with the final annual rate and bill impact dollars and percentages shall be filed with the board at the time of customer notification.

(4) A statement that the board will be conducting a contested case proceeding to review the application and that a customer may file comments in the board's electronic filing system.

(5) The telephone numbers; websites; email addresses; and mailing addresses of the utility, the board, and the consumer advocate for the customer to contact with questions.

199—35.4(476) Assessment of potential and collaboration.

35.4(1) *Assessment of potential.* The utility shall conduct an assessment of potential study to determine the cost-effective energy and capacity savings available in accordance with Iowa Code section 476.6(15). The utility's assessment shall address the potential energy and capacity savings in each of ten years subsequent to the year the assessment is filed and include economic and impact analyses of measures that address benefits and costs over the entire estimated useful lives of energy efficiency measures.

35.4(2) *Collaboration.* A utility shall offer interested persons the opportunity to participate in the development of its energy efficiency and demand response plans by providing the opportunity for interested persons to offer suggestions for programs, to offer suggestions for the assessment of potential, and to review and comment on the utility's draft of the assessment of potential and energy efficiency and demand response plans. The utility may analyze proposals from participants to help determine the effects of the proposals on the utility's plan. A participant is responsible for providing sufficient supporting information to enable the utility to analyze the participant's proposal. The opportunity to participate shall commence at least 180 days prior to the date the utility submits the utility's energy efficiency and demand response plans and assessment of potential to the board.

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

35.5(1) Each electric and natural gas utility shall file with the board 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, the assessment of potential, and the Iowa Technical Reference Manual.

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 board 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 board 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 board 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 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 board 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.

199—35.6(476) Contested case proceeding.

35.6(1) The board shall conduct a contested case proceeding for the purpose of developing specific capacity and energy savings performance standards for each utility required to be rate-regulated and reviewing energy efficiency and demand response plans and budgets designed to achieve those savings.

35.6(2) Within 30 days after filing, each application for approval of an energy efficiency and demand response plan that is submitted with the information and supporting documentation required by this chapter, and that complies with the filing requirements of 199—Chapter 14, shall be docketed as a contested case proceeding. The Iowa economic development authority shall be considered a party to the proceeding. The proceeding shall follow the applicable provisions of 199—Chapter 7.

35.6(3) With the filing of a utility's application for approval of the utility's energy efficiency plan, each utility shall provide, for the board's review, a calculation of the percentage of the utility's expected annual Iowa retail rate revenue, which the utility shall determine by dividing the total projected budget for the five-year plan by the total projected Iowa retail rate revenues for the five-year plan period. The calculation of a utility's percentage of Iowa retail rate revenue may be

subject to confidential treatment under Iowa Code chapters 22 and 550 upon request of the utility and as determined by the board based on the board's review of such request.

199—35.7(476) Exemptions from participation.

35.7(1) The utility shall allow customers to request exemption from participating in the utility's electric energy efficiency plan if the combined ratepayer impact test result for the utility's approved five-year electric energy efficiency and demand response plan is less than 1.0. The utility shall file a draft customer notice within 20 days following the board's approval of the utility's five-year energy efficiency plan. The form of the notice, once approved by the board, shall not be altered except to include the rate and bill impact dollars and percentages. The type size and quality shall be easily legible. The notice shall, at a minimum, provide the following elements:

a. A brief statement informing all customers that they are eligible to request an exemption from participation in the utility's electric energy efficiency plan.

b. The estimated annual rate and bill impacts of the approved electric energy efficiency plan on each class of customers and an estimate of the annual jurisdictional rate impact for each major customer grouping in dollars and as a percentage, with the proposed actual increases to be filed at the time of notice to customers. The utility may represent the estimated annual rate and bill impact dollars and percentages with blank spaces; however, the board may require the utility to submit additional information necessary for review of the proposed form of notice. A copy of the notice with the final annual rate and bill impact dollars and percentages shall be filed with the board at the time of customer notification.

c. A statement that customers requesting to be exempt from participation in the electric energy efficiency plan will not be eligible to participate in any utility-sponsored electric energy efficiency programs and will not be eligible to receive rebates from the utility for electric energy efficiency programs during the five-year plan cycle, beginning January 1 of the first year of the five-year plan cycle.

d. An explanation that customers requesting to be exempt from participation in the electric energy efficiency plan will no longer be assessed the energy efficiency cost recovery factor for the electric energy efficiency programs on their utility bills.

e. An explanation that customers requesting to be exempt from participation in the electric energy efficiency plan will be eligible to participate in demand response and natural gas energy efficiency programs and will be assessed costs related to those programs on their utility bills.

f. A statement that the exemption from participation in the electric energy efficiency plan is applicable for the five-year plan cycle. The ability to request an exemption from participation in future electric energy efficiency plans will depend on the specifics of the utility's energy efficiency plan and demand response plan filing as approved by the board.

g. The utility's telephone number, website address, and email address the customer should use to request an exemption from participation in the electric energy efficiency plan.

h. A deadline by which customers must request an exemption. The deadline shall not be less than 30 days from the date of the notice.

35.7(2) The utility shall deliver the approved notice to all affected customers within 30 days of board approval.

199—35.8(476) Annual reporting requirements. Each utility shall file by May 1 of each year an energy efficiency annual report that shall include the utility's energy efficiency and demand response spending compared to the approved budgets; actual demand and energy savings compared to the performance standards approved by the board; cost-effectiveness results for the prior calendar year; the results of any monitoring and verification activities; and any additional information pertinent to the implementation or performance of the energy efficiency or demand response plan for the previous calendar year, such as changes in outside firms used to implement energy efficiency programs, updates on pilot projects, and other information as required by board order.

199—35.9(476) Energy efficiency and demand response cost recovery. Each utility shall be allowed to recover the authorized energy efficiency and demand response plan expenditures adjusted for any overcollections or undercollections calculated on an annual basis. The utility may propose to recover the portion of the costs of process-oriented industrial assessments related to energy efficiency.

35.9(1) *Accounting for costs.* Each utility shall maintain accounting plans and procedures to account for all energy efficiency and demand response costs.

a. Each utility shall maintain a subaccount system, work order system, or accounting system that identifies individual costs by each program.

b. Each utility shall maintain accurate employee, equipment, material, and other records that identify all amounts related to each individual energy efficiency or demand response program.

35.9(2) *Automatic adjustment mechanism.* Each utility shall file by June 1 of each year energy efficiency and demand response costs proposed to be recovered in rates for the 12-month recovery period beginning at the start of the first utility billing month at least 30 days following board approval.

35.9(3) *Energy efficiency cost recovery (EECR) and demand response cost recovery (DRCR) factors.* Each utility shall calculate an EECR factor to recover the costs associated with the energy efficiency plan, and each electric utility shall also calculate a DRCR factor to recover costs associated with the demand response plan. The utility shall calculate EECR/DRCR factors separately for each customer classification or grouping previously approved by the board. A utility shall not use customer classifications or allocations of indirect or other related costs, other than those previously approved by the board, without filing for a modification of the energy efficiency and demand response plan and receiving board approval.

a. EECR/DRCR factors shall be calculated according to the following formula:

$$\text{EECR/DRCR factor} = \frac{\text{authorized recovery} + \text{overcollection/undercollection}}{\text{annual sales units}}$$

b. EECR/DRCR factor is the energy efficiency or demand response recovery amount per unit of sales.

c. Authorized recovery is the difference between the actual energy efficiency or demand response expenditures by customer class for the previous calendar year and the approved energy efficiency or demand response budget by customer class for the previous calendar year plus the approved energy efficiency or demand response budget by customer class for the current calendar year.

d. Overcollection or undercollection is the actual amount recovered by customer class for the previous recovery period less the amount authorized to be recovered by customer class for the previous recovery period. Overcollection or undercollection may also include adjustments ordered by the board in prudence reviews.

e. Annual sales units are the estimated sales for the 12-month recovery period for customers who have not requested an exemption as allowed by rule 199—35.7(476).

35.9(4) *Filing requirements.* Each utility proposing to recover energy efficiency or demand response costs through an automatic adjustment mechanism shall provide the following information:

a. Restatement of the derivation of each EECR/DRCR factor previously approved by the board.

b. New EECR/DRCR factors based on allocation methods and customer classifications and groupings approved by the board in previous proceedings.

c. All worksheets and detailed supporting data used to determine new EECR/DRCR factors. Information already on file with the board may be incorporated by reference in the filing.

d. A reconciliation comparing the amounts actually collected by the previous EECR/DRCR factors to the amounts expended. Overcollection or undercollection shall be used to compute adjustment factors.

e. If the board has determined in a prudence review that previously recovered energy efficiency or demand response costs were imprudently incurred, adjustment factors that shall include reductions for these amounts.

35.9(5) *Tariff sheets.* Upon approval of the new EECR/DRCR factors, the utility shall file separate tariff sheets for board approval to implement the EECR/DRCR factors in the utility's rates.

35.9(6) *Customers' bills.*

a. Each electric and natural gas utility shall include the EECR factor, the customer's usage, and the dollar amount charge on the customer's bill. Customers who receive one bill for electric and natural gas service shall have a separate line item on the bill for the electric EECR and the natural gas EECR.

b. Each electric utility shall represent the DRCR factor, the customer's usage, and the dollar amount charge on the customer's bill.

199—35.10(476) Modification of an approved plan.

35.10(1) An approved energy efficiency plan or an approved demand response plan and associated budget may be modified if the modification is approved by the board.

a. Electric utilities may request a modification to an approved energy efficiency plan due to changes in the funding as a result of customers requesting exemptions from the electric energy efficiency plan.

b. Natural gas and electric utilities may request modification of an approved energy efficiency plan, or electric utilities may request modification of an approved demand response plan, for any reason.

c. The board, on its own motion, may consider modification of the energy efficiency or demand response plan and budget.

35.10(2) All applications to modify shall be filed in the same docket in which the energy efficiency or demand response plan was approved. All parties to the docket in which the energy efficiency or demand response plan was approved shall be served copies of the application to modify and have 14 days to file an objection or agreement. Objections should be specifically related to the contents of the modification. Failure to file timely objection shall be deemed agreement.

35.10(3) Each application to modify an approved energy efficiency or demand response plan shall include:

a. A statement of the proposed modification and the party's interest in the modification.

b. An analysis supporting the requested modification.

c. An estimated implementation schedule for the modification.

d. A statement of the effect of the modification on attainment of the utility's performance standards and on projected results, including cost-effectiveness, of the utility's implementation of the utility's plan.

35.10(4) If the board finds that any reasonable grounds exist to investigate the proposed modification, a procedural schedule shall be set and the board shall take action within 90 days after the modification request is filed.

35.10(5) If an application to modify is filed and the board finds that there is no reason to investigate, then the board shall issue an order within 90 days after the modification request is filed stating the reasons for the board's decision relating to the application.

35.10(6) If the board rejects or modifies a utility's plan, the board may require the utility to file a modified plan and may specify the minimum acceptable contents of the modified plan.

199—35.11(476) Prudence review.

35.11(1) The board shall periodically conduct a contested case proceeding to evaluate the reasonableness and prudence of the utility's implementation of energy efficiency and demand response plans and budgets. The prudence review shall be based upon the information filed by a utility in the annual report required by rule 199—35.8(476) or based on discovery conducted in review of the annual reports.

35.11(2) The consumer advocate or another person may request the board to conduct a prudence review based upon the information filed by a utility in the annual report required by rule 199—35.8(476) or based on discovery conducted in review of the annual reports. The request to initiate the prudence review shall identify specific issues to be evaluated and may include a proposed procedural schedule.

35.11(3) The board shall determine whether a contested case proceeding is necessary to address the issues raised in a request for a prudence review.

35.11(4) Disallowance of past costs. If the board finds the utility did not take all reasonable and prudent actions to cost-effectively implement its energy efficiency or demand response programs, the board shall determine the amount in excess of those costs that would have been incurred under reasonable and prudent implementation. That amount shall be deducted from the next EECR/DRCR factors calculated pursuant to subrule 35.9(3) until the disallowed costs have been satisfied.

199—35.12(476) New structure energy conservation standards. A utility providing natural gas or electric service shall not provide service to any structure completed after April 1, 1984, unless the owner or builder of the structure has certified to the utility that the building conforms to the energy conservation requirements adopted under 661—Chapter 303. If this compliance is already being certified to a state or local agency, a copy of that certification shall be provided to the utility. If no state or local agency is monitoring compliance with these energy conservation standards, the owner or builder shall certify that the structure complies with the standards by signing a form provided by the utility. No certification will be required for structures that are not governed by 661—Chapter 303.

These rules are intended to implement Iowa Code section 476.6.