

TITLE 170 INDIANA UTILITY REGULATORY COMMISSION

Proposed Rule

LSA Document #15-xxx

DIGEST

Amends 170 IAC 4-7 to update the commission's rule requiring electric utilities to prepare and submit integrated resource plans and amends 170 IAC 4-8 to update the commissions rule regarding utilities' energy efficiency plans. Effective 30 days after filing with the Publisher.

170 IAC 4-7-0.5

170 IAC 4-7-1

170 IAC 4-7-2

170 IAC 4-7-2.1

170 IAC 4-7-2.2

170 IAC 4-7-2.5

170 IAC 4-7-2.6

170 IAC 4-7-2.7

170 IAC 4-7-3

170 IAC 4-7-4

170 IAC 4-7-5

170 IAC 4-7-6

170 IAC 4-7-7

170 IAC 4-7-8

170 IAC 4-7-9

170 IAC 4-7-10

170 IAC 4-8-1

170 IAC 4-8-2

170 IAC 4-8-3

170 IAC 4-8-4

170 IAC 4-8-5

170 IAC 4-8-6

170 IAC 4-8-7

170 IAC 4-8-8

SECTION 1. 170 IAC 4-7-0.5 IS ADDED TO READ AS FOLLOWS

170 IAC 4-7-0.5 Purpose and Applicability

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-2.2; IC 8-1-2.3-2; IC 8-1-2.4; IC 8-1-8.5; IC 8-1-8.8-10; IC 8-1.5

Sec. 0.5 (a) The purpose of this rule is to provide the specific requirements for submission of utilities' integrated resource plans required by IC 8-1-8.5.

(b) This rule applies to a utility, as defined in this rule, unless otherwise noted. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-0.5*)

SECTION 2. 170 IAC 4-7-1 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-1 Definitions

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-2.2; IC 8-1-2.3-2; IC 8-1-2.4; IC 8-1-8.5; IC 8-1-8.8-10; IC 8-1.5

Sec. 1. (a) The definitions in this section apply throughout this rule.

(b) [CJ1]“Avoided cost” means the incremental cost to a utility of energy or capacity, or both, not incurred by a utility if an alternative supply-side resource or demand-side resource is included in the utility’s IRP.

(c) “Candidate resource portfolio” means one of multiple long-term resource portfolios selected for further evaluation through the utility’s portfolio screening process to determine the preferred resource portfolio.

(d) “Cogeneration facility” means the following:

(1) A facility that simultaneously generates electricity and useful thermal energy and meets the energy efficiency standards established for a cogeneration facility by the Federal Energy Regulatory Commission (FERC) under 16 U.S.C. 824a-3.

(2) The land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility.

(3) The transmission or distribution facilities necessary to conduct the energy produced by the facility to a user located at or near the project site.

(e) “Commission” means the Indiana utility regulatory commission.

(f) “Commission analysis” means the required state energy analysis developed by the commission under IC 8-1-8.5-3.

(g) “Contemporary issues” means any topic that may affect the inputs, methods, or judgment factors in an IRP and is common to the utilities. Topics may include, but are not limited to, the following:

(1) Economic.

(2) Financial.

(3) Environmental.

(4) Energy.

(5) Demographic.

(6) Customer.

(7) Methodological.

(8) Regulatory.

(9) Technological.

(h) “Contemporary methods” means any methodological aspect involved with developing an IRP that represents the best practice of the electric industry to improve the quality of an IRP.

(i) “Demand-side management program” or “DSM[CJ2] program” means a utility program designed to implement demand response, energy efficiency, or both.

(j) “Demand response” means a reduction in demand for limited intervals of time, such as during peak electricity usage or emergency conditions.

(k) “Demand-side resource” means one or more demand-side management programs.

(l) "Director" means an employee of the commission designated as the IRP director by the commission's agency head appointed under IC 8-1-1-2(d).

(m) "Distributed generation" means an electrical generating facility located at or near a customer's point of use, ten megawatts or less and connected at a voltage less than or equal to 60 kilovolts, which may be connected in parallel operation to the utility system.

(n) "DSM costs" refers to all expenses incurred by a utility in a given year for operation of a DSM program, whether the cost is capitalized or expensed. Expenses include, but are not limited to, the following:

- (1) Administration.
- (2) Equipment.
- (3) Incentives paid to program participants.
- (4) Marketing and advertising.
- (5) Evaluation, measurement and verification.

(o) "Emission allowance" means the authority to emit one (1) unit of any air pollutant as specified by a federal or state regulatory system.

(p) "End-use" means the light, heat, cooling, refrigeration, motor drive, microwave energy, video or audio signal, computer processing, electrolytic process, or other useful work produced by equipment using electricity

(q) "Energy efficiency" means reduced energy use for a comparable or improved level of energy service.

(r) "Energy service" means the light, heat, motor drive, and other service for which a customer purchases electricity from the utility.

(s) "Energy storage" means a:

- (1) technology; or
- (2) set of technologies;

Capable of storing previously generated electric energy and discharging that energy as electricity at a later time.

(t) "Engineering estimate" means a calculated estimate of the change in energy (kWh) and demand (kW) resulting from a DSM program, accounting for dynamic interactions between or among them.

(u) "FERC Form 715" means the annual transmission planning and evaluation report required by the Federal Energy Regulatory Commission (FERC), as adopted in 58 FR 52436, Oct. 8, 1993, and as amended by Order 643, 68 FR 52095, Sep. 2, 2003.

(v) "Firm wholesale power sale" means a power sale intended to be available to the purchaser at all times, including under adverse conditions, during the period covered by the commitment.

(w) "Integrated resource plan" or "IRP" means a utility's document or documents submitted to the commission in order to meet the requirements of this rule.

(x) "Load building" means a program intended to increase electricity consumption without regard to the timing of the increased usage.

(y) "Load research" means the collection of electricity usage data through a metering device associated with an end-use, a circuit, or a building. The metered data is used to better understand the characteristics of electric loads, the timing of their use, and the amount of electricity consumed by users. The data may be collected over a variety of time intervals, usually sixty (60) minutes or less.

(z) "Load shape" means the time pattern of customer electricity use and the relationship of the level of energy use to a specific time during the day, month, and year.

(aa) "North American Industrial Classification System" or "NAICS" refers to the system developed by the United States Department of Commerce for use in the classification of establishments by type of activity in which engaged.

(bb) "Participant cost test" means a cost-effectiveness test that measures the difference between the cost incurred by a program participant and the direct economic benefit received by a program participant.

(cc) "Penetration" means the ratio of the number of a specific type of new appliances or end-use equipment installed to the total number installed during a given time.

(dd) "Power transfer capability" means the amount of power that can be transferred from one point or part of the bulk electric system to another without exceeding any reliability criteria pertinent to the utility.

(ee) "Preferred resource portfolio" means the utility's selected long-term supply-side resource and demand-side resource mix that economically, safely and reliably meets electric system demand.

(ff) "Present value" means today's value of a future payment, or stream of payments, discounted by an interest rate.

(gg) "Program Participant" means a utility customer participating in a DSM program.

(hh) "Public advisory process" refers to the procedures in section 2.1 of this rule in which customers and interested parties have the opportunity to receive information from the utilities, provide input for the utility to consider in the development of the IRP, and comment on a utility's IRP.

(ii) "Ratepayer impact measure test" or "RIM test" is the change in revenue requirement, expressed on a per unit of sale, from the implementation of a DSM program.

(jj) "Regional transmission organization" or "RTO" means the regional transmission organization approved by the Federal Energy Regulatory Commission for the control area that includes the utility's assigned service area as defined in IC 8-1-2.3-2.

(kk) "Renewable resource" means a renewable energy resource as defined in IC 8-1-8.8-10.

(ll) "Resource" means a facility, project, contract, or other mechanism used by a utility to assist in providing electric energy service to the customer.

(mm) "Resource action" means a resource change or addition proposed by a utility in a formally docketed commission proceeding.

(nn) "Risk metric" means a measure used to gauge the risk associated with a resource portfolio. As applied to the cost of a resource portfolio, this includes measures of the variability of costs and the magnitude of outcomes.

(oo) "Saturation" means the ratio of the number of a specific type of similar appliances or end use equipment to the total number of customers in that class or the total number of similar appliances or end use equipment in use.

(pp) "Screening" means an evaluation performed by a utility to determine whether a demand-side or supply-side resource option is eligible for potential inclusion in the utility's preferred resource portfolio

(qq) "Short term action plan" means a schedule of activities and goals developed by a utility to begin efficient implementation of its preferred resource portfolio as required by subdivision 4(10) of this rule.

(rr) "Smart grid" means use of digital electronics, equipment, or data, and the associated communications networks, to monitor and control aspects of the electrical transmission and distribution system from generation to consumption.

(ss) "Supply-side resource" means a resource that provides a supply of electrical energy or capacity, or both, to a utility. A supply-side resource may include, but is not limited to, the following:

- (1) A utility-owned generation capacity addition.
- (2) A wholesale power purchase.
- (3) Refurbishing or upgrading an existing utility-owned generation facility.
- (4) A cogeneration facility.
- (5) A renewable resource.
- (6) Distributed generation.

(tt) "Total resource cost test" means a cost-effectiveness test that eliminates the distinction between a participant and nonparticipant by analyzing whether a resource is cost effective based on the total cost and benefit of a DSM program, independent of the precise allocation to a shareholder, ratepayer, and participant.

(uu) "Utility" means:

- (1) a public, municipally owned, or cooperatively owned electric utility; or
- (2) a joint agency created under IC 8-1-2.2;

unless the utility is exempt under IC 8-1-8.5-7.

(vv) "Utility cost test" (also known as the revenue requirements test, or program administrator cost test) means a cost-effectiveness test measuring the ratio of the utility benefits to utility costs. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-1; filed Aug 31, 1995, 9:00 a.m.: 19 IR 16; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA*)

SECTION 3. 170 IAC 4-7-2 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-2 Integrated Resource Plan Submission

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 5-14-3; IC 8-1-1-8; IC 8-1-8.5; IC 8-1.5

Sec. 2. (a) The following utilities, or their successors in interest, shall submit to the commission an IRP consistent with this rule according to the following schedule:

(1) Indianapolis Power and Light Company, Northern Indiana Public Service Company, and Southern Indiana Gas and Electric Company by November 1, 2016, and every three years thereafter.

(2) Indiana Municipal Power Agency, Hoosier Energy Rural Electric Cooperative and Wabash Valley Power Association by November 1, 2017, and every three years thereafter.

(3) Duke Energy Indiana, and Indiana Michigan Power Company, by November 1, 2018, and every three years thereafter.

(4) Hoosier Energy Rural Electric Cooperative shall submit an update of its 2014 IRP by November 1, 2016, consistent with subsection 10(b) of this rule.

(b) Prior to constructing, purchasing, or leasing a generating facility to provide electric service within the state of Indiana, a utility not listed in subsection (a) must submit to the

commission an IRP consistent with this rule. If the generating facility is thereafter constructed, purchased, or leased, the utility shall submit to the commission an IRP consistent with this rule every three years from the date of the utility's first IRP.

(c) Upon request of a utility, the director may grant an extension of a submission deadline, for good cause shown.

(d) On or before the applicable date, a utility subject to subsection (a) or (b) must submit electronically to the director or through an electronic filing system if requested by the director, the following documents:

(1) The integrated resource plan.

(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the assumptions in the IRP.

(3) An IRP summary that communicates core IRP concepts and results to non-technical audiences in a simplified format using visual elements where appropriate. The IRP summary shall include, but is not limited to, the following:

(A) A brief description of the utility's:

(i) existing resources;

(ii) preferred resource portfolio;

(iii) key factors influencing the preferred resource portfolio;

(iv) short term action plan;

(v) the IRP public advisory process; and

(vi) any additional details the commission staff may request.

(B) A simplified discussion of resource types and load characteristics.

The utility shall make the IRP summary readily accessible on its website.

(e) Contemporaneously with the submission of an IRP under this section, a utility shall provide to the director the following information:

(1) The name and address of each known individual or entity considered by the utility to be an interested party.

(2) A statement that the utility has sent each known interested party, electronically or by deposit in the United States mail, First Class postage prepaid, a notice of the utility's submission of the IRP to the commission. The notice must include the following information:

(A) A general description of the subject matter of the submitted IRP.

(B) A statement that the commission invites interested parties to submit written comments on the utility's IRP within 120 days of the IRP submittal.

An interested party includes any business, organization, or particular customer that participated in the utility's previous public advisory process or submitted comments on the utility's previous IRP submission. A utility is not required to separately notify all of its customers.

(3) A statement that the utility has served a copy of the documents submitted under subsection (d) above on the office of the consumer counselor. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-2; filed Aug 31, 1995, 9:00 a.m.: 19 IR 18; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA; errata filed Jul 21, 2009, 1:33 p.m.: 20090819-IR-170090571ACA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA*)

SECTION 4. 170 IAC 4-7-2.1 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-2.1 Public Comments and Director's Reports

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 5-14-3; IC 8-1-1-8; IC 8-1-8.5; IC 8-1.5

Sec. 2.1. (a) A customer or interested party may comment on an IRP submitted to the commission. A comment must:

- (1) be in writing;
- (2) be received by the commission within one hundred and twenty (120) days from the date a utility submits its IRP to the commission;
- (3) be ~~submitted to the commission~~ electronically submitted to the director or submitted through an electronic filing system if requested by the director;
- (4) clearly identify the utility upon which written comments are submitted; and
- (5) be provided to the utility.

(b) The director shall issue a draft report on the IRP no later than one hundred and fifty (150) days from the date a utility submits its IRP to the commission.

(c) Supplemental or response comments may be submitted by:

- (1) the utility;
- (2) any customer; or
- (3) any interested party.

(d) Supplemental or response comments must be:

- (1) in writing;
- (2) received by the commission within thirty (30) days from the date the director issues the draft report;
- (3) ~~submitted to the commission~~ electronically submitted to the director or submitted through an electronic filing system if requested by the director; and
- (4) provided to:

- (A) the utility;
- (B) each customer or interested party that submitted written comments; and
- (C) the office of the utility consumer counselor.

(e) The director may allow additional written comment periods or extend the submission deadline for written comments or supplemental or response comments by notifying the utility and interested parties.

(f) The director shall issue a final report on the IRP within 30 days following the deadline for supplemental or response comments.

(g) The draft report and the final report shall:

- (1) be limited to commenting on the IRP's compliance with the requirements of this rule;
- (2) list all areas where the director believes the IRP fails to comply with the requirements of this rule or other regulatory obligation in statute or rule; and
- (3) not comment on:

- (A) the desirability of the utility's preferred resource plan; and
- (B) a proposed resource action in the IRP.

(h) The director may extend the deadlines for issuance of the draft report and the final report by notifying the utility and interested parties.

(i) Failure by the director to issue a draft or final report by the applicable deadline shall result in a presumption that the IRP complies with this rule.

(j) Subject to IC 5-14-3 and any determination by the commission regarding confidentiality under 170 IAC 1-1.1-4, the commission shall make publically available on the commission's website or other electronic document system:

- (1) The utilities' IRPs.
- (2) Written comments.
- (3) Supplementary and responsive comments.
- (4) The director's draft report.
- (5) The director's final report. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-2.1*)

SECTION 5. 170 IAC 4-7-2.2 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-2.2 Resource Adequacy Annual Updates

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 5-14-3; IC 8-1-1-8; IC 8-1-8.5; IC 8-1.5

Sec. 2.2. (a) On or before November 1 of each year, each utility listed in subsection 2(a) of this rule shall provide to the director the resource adequacy information the utility provided to a regional transmission organization in the preceding year.

(b) A utility providing information as required in subsection (a) shall explain any differences in the information provided under subsection (a) with the utility's most recent IRP. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-2.2*)

SECTION 6. 170 IAC 4-7-2.5 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-2.5 Effects of Integrated Resource Plans in Docketed Proceedings

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 5-14-3; IC 8-1-1-8; IC 8-1-8.5; IC 8-1.5

Sec. 2.5. (a) The failure of an interested party to file comments under this rule shall not constitute a waiver of any right to participate as a party or to advance an argument or position in a formally docketed proceeding before the commission. Similarly, the content of comments filed by an interested party under this rule shall not estop or preclude that party from advancing an argument or position in a formally docketed proceeding before the commission, whether or not that argument or position was raised in comments submitted under this rule.

(b) When a utility takes a resource action, it shall be consistent with the most recent IRP submitted under this rule, including its:

- (1) inputs;
- (2) data and assumptions;
- (3) methods;
- (4) models;
- (5) judgment factors; and
- (6) rationales used to determine inputs, methods, and risk metrics;

unless any discrepancies between the most recent IRP and the resource action are fully explained and justified with supporting evidence, including an updated IRP analyses.

(c) Documents submitted to the commission or created pursuant to this rule may be used as follows:

- (1) To assist the commission in the preparation of the commission analysis.
- (2) In the preparation of a commission staff report in formally docketed proceedings before the commission.
- (3) As evidence in a formally docketed proceeding before the commission when admitted.

(Indiana Utility Regulatory Commission; 170 IAC 4-7-2.5)

SECTION 7. 170 IAC 4-7-2.6 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-2.6 Public advisory process

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5

Sec. 2.6. (a) The following utilities are exempt from this section:

- (1) A municipally owned utility.
- (2) A cooperatively owned utility
- (3) A utility submitting an IRP under subsection 2(b) of this rule.

(b) The utility shall provide information requested by an interested party relating to the development of the utility's IRP.

(c) The utility shall solicit, consider, and timely respond to all relevant input relating to the development of the utility's IRP provided by interested parties, the commission, and its staff.

(d) The utility retains full responsibility for the content of its IRP.

(e) The utility shall conduct a public advisory process as follows:

(1) Prior to submitting its IRP to the commission, the utility shall hold at least three meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following:

(A) An introduction to the IRP and public advisory process.

(B) The utility's load forecast.

(C) Evaluation of existing resources.

(D) Evaluation of supply and demand-side resource alternatives, including:

(i) associated costs;

(ii) quantifiable energy and non-energy benefits; and

(iii) performance attributes.

(E) Modeling methods.

(F) Modeling inputs.

(G) Treatment of risk and uncertainty.

(H) Discussion seeking input on its candidate resource portfolios.

(I) The utility's scenarios and sensitivities.

(J) Discussion of the utility's preferred resource portfolio and its rationale.

(2) The utility is encouraged to hold additional meetings as appropriate.

(3) The schedule for meetings shall be determined by the utility and shall:

(A) be consistent with its internal IRP development schedule; and

(B) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP.

(4) The utility or its designee shall:

(A) chair the participation process;

- (B) schedule meetings; and
- (C) develop and publish to its website agendas and relevant material for those meetings at least seven (7) calendar days prior to the meeting; and
- (D) develop and publish to its website minutes within fifteen (15) calendar days following each meeting;
- (5) Interested parties may request that relevant items be placed on the agenda of the meetings if they provide adequate notice to the utility.
- (6) The utility shall take reasonable steps to notify:
 - (A) its customers;
 - (B) the commission; and
 - (C) interested partiesof its public advisory process. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-2.6*)

SECTION 8. 170 IAC 4-7-2.7 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-2.7 Contemporary issues technical conference

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5

Sec. 2.7. (a) The commission or its staff may host an annual technical conference to facilitate:

- (1) identifying contemporary issues;
- (2) identifying best practices to manage contemporary issues; and
- (3) instituting a standardized IRP format.

(b) The agenda of the technical conference shall be set by the commission staff. Utilities and interested parties may request commission staff include specific contemporary issues and presenters.

(c) The director may designate specific contemporary issues for utilities to address in the next IRPs by providing the utilities and interested parties with the contemporary issues to be addressed. The utility shall address the designated contemporary issues in its next IRP. In addition, prior to its next IRP the utility shall provide to interested parties either a discussion of the impacts of such issues on its IRP or describe how it has taken the contemporary issues into account.

(d) A utility shall address new issues raised in a contemporary issues technical conference if the contemporary issues technical conference occurred at least one (1) year prior to the submittal date of a utility's IRP. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-2.7*)

SECTION 9. 170 IAC 4-7-3 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-3 Waiver or variance requests

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 5-14-3; IC 8-1-2-29; IC 8-1-2.2; IC 8-1-8.5-7; IC 8-1.5

Sec. 3. (a) A utility may request a variance from a provision of this rule for good cause.

(b) A request under this section shall:

- (1) Describe the situation which necessitates the variance.

- (2) Identify the provision of this rule for which the variance is requested.
- (3) Explain the difference between the expected effects of complying with this rule on the utility, its customers, and interested parties in the public advisory process if the variance is denied and the expected effect on the parties if accepted.
- (4) Explanation of how the variance is expected to aid the implementation of this rule.
- (5) A request shall be submitted in sufficient time that the IRP submittal schedule shall not be adversely affected.

(c) The director shall respond in writing regarding acceptance or denial of a request under this section within fifteen (15) calendar days. The request shall not be unreasonably denied, and any denials shall include the reason for the denial. If the director fails to respond within fifteen (15) calendar days, the request shall be deemed accepted.

(d) The request by the utility and the director's acceptance or denial shall be posted on the commission's website or other publically accessible electronic document system.

(e) An appeal to the full commission of the director's acceptance or denial under this section must be filed with the commission within thirty (30) days of the posting of the director's written acceptance or denial of the request. *(Indiana Utility Regulatory Commission; 170 IAC 4-7-3; filed Aug 31, 1995, 9:00 a.m.: 19 IR 19; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA)*

SECTION 10. 170 IAC 4-7-4 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-4 Integrated Resource Plan Contents

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1; IC 8-1.5

Sec. 4. An IRP must include the following:

- (1) At least a 20 year future period for a predicted or forecasted analysis.
- (2) An analysis of historical and forecasted levels of peak demand and energy usage in compliance with subsection 5(a) of this rule.
- (3) At least three (3) alternative forecast scenarios of peak demand and energy usage in compliance with subsection 5(b) of this rule.
- (4) A description of the utility's existing resources in compliance with subsection 6(a) of this rule.
- (5) A description of possible alternative methods of meeting future demand for electric service in compliance with subsection 6(b) of this rule.
- (6) The resource screening analysis and resource summary table required in subsection 7(a) of this rule.
- (7) The information and calculation of tests required for potential resources in compliance with subsections 7(b)-7(e) of this rule.
- (8) A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with subsection 8(a) and 8(b) of this rule.
- (9) A description of the utility's preferred resource portfolio and the information required in compliance with subsection 8(b) of this rule.
- (10) A short term action plan listing plans for the next three year period to implement the utility's preferred resource portfolio and its workable strategy. The short term action plan shall comply with section 9 of this rule.

(11) A discussion of the:

- (A) inputs;
- (B) methods; and
- (C) definitions

used by the utility in the IRP.

(12) Appendices of the data sets and data sources used to establish alternative forecasts in subsection 9(b) of this rule. If the IRP references a third party data source, the IRP must include the following for the relevant data:

- (A) source title;
- (B) author;
- (C) publishing address;
- (D) date;
- (E) page number; and
- (F) an explanation of any adjustments made to the data.

The data must be submitted with the IRP in a manipulable format.

(13) A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by the following:

- (A) customer class;
- (B) rate class;
- (C) NAICS code;
- (D) DSM program; and
- (E) end-use.

(14) The database in subdivision (13) may be developed using, but not limited to, the following methods:

- (A) Load research developed by the individual utility.
- (B) Load research developed in conjunction with another utility.
- (C) Load research developed by another utility and modified to meet the characteristics of that utility.
- (D) Engineering estimates.
- (E) Load data developed by a non-utility source.

(15) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns.

(16) A discussion detailing how information from Advanced Metering Infrastructure (AMI) and smart grid will be used to enhance usage data and improve load forecasts, DSM programs, and other aspects of planning.

(17) A discussion of distributed generation within the service territory and its potential effects on generation, transmission, and distribution planning and load forecasting.

(18) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.

(19) A discussion of how the utility's fuel inventory and procurement planning practices, have been taken into account and influenced the IRP development.

(20) A discussion of how the utility's emission allowance inventory and procurement practices for any air emission have been taken into account and influenced the IRP development.

- (21) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.
- (22) A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.
- (23) A discussion of how the utilities' resource planning objectives, such as cost effectiveness, rate impacts, risks and uncertainty, were balanced in selecting its preferred resource plan.
- (24) A description and analysis of the utility's base case scenario, sometimes referred to a business as usual case or reference case. The base case scenario is the most likely future scenario and must meet the following criteria:
- (A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections, and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs.
 - (B) Include existing federal environmental laws; existing state laws, such as renewable energy requirements and energy efficiency laws; and existing policies, such as tax incentives for renewable resources that are certain. Existing laws or policies continuing throughout at least some portion of the planning horizon with a high probability of expiration or repeal must be eliminated or altered when applicable.
 - (C) Not include future resources, laws, or policies unless the utility receives stakeholder input on the inclusion and it meets the following conditions:
 - (i) Future resources have obtained regulatory approvals.
 - (ii) Future laws and policies have a high probability of being enacted.
- A base case need not align with the utility's preferred resource portfolio.
- (25) A description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario.
- (26) A brief description, focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715:
- (A) The most current power flow data models, studies, and sensitivity analysis.
 - (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. This description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC).
 - (C) Reliability criteria for transmission planning as well as the assessment practice used. This description must include the following:
 - (i) the limits of the utility's transmission use;
 - (ii) the utility's assessment practices developed through experience and study; and
 - (iii) operating restrictions and limitations particular to the utility.
- (27) A list and description of the contemporary methods utilized by the utility in developing the IRP, including the following:
- (A) For models used in the IRP, the model's structure and reasoning for its use.

- (B) The utility's effort to develop and improve the methodology and inputs, including for its:
- (i) load forecast;
 - (ii) forecasted impact from demand-side programs;
 - (iii) cost estimates; and
 - (iv) analysis of risk and uncertainty.
- (28) An explanation, with supporting documentation, of the avoided cost calculation. An avoided cost must be calculated for each year in the forecast period. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include, but is not limited to, the following:
- (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement.
 - (B) The avoided transmission capacity cost.
 - (C) The avoided distribution capacity cost.
 - (D) The avoided operating cost, including fuel, plant operation and maintenance, spinning reserve, emission allowances, environmental and health costs, and transmission and distribution operation and maintenance.
- (29) The actual demand for all hours of the most recent historical year available, which shall be submitted electronically in a manipulable format. For purposes of comparison, a utility must maintain three (3) years of hourly data.
- (30) A summary of the utility's most recent public advisory process, including:
- (A) Key issues discussed.
 - (B) How the utility responded to the issues
 - (C) A description of how stakeholder input was used in developing the IRP.
- (31) A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-4; filed Aug 31, 1995, 9:00 a.m.: 19 IR 20; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA*)

SECTION 11. 170 IAC 4-7-5 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-5 Energy and demand forecasts

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 5. (a) The analysis of historical and forecasted levels of peak demand and energy usage must include the following:

- (1) Historical load shapes, including, but not limited to, the following:
 - (A) Annual load shapes.
 - (B) Seasonal load shapes.
 - (C) Monthly load shapes.
 - (D) Selected weekly load shapes.
 - (E) Selected daily load shapes, which shall include summer and winter peak days, and a typical weekday and weekend day.

- (2) Disaggregation of historical data and forecasts by customer class, interruptible load, end-use where information permits.
- (3) Actual and weather normalized energy and demand levels.
- (4) A discussion of methods and processes used to weather normalize.
- (5) A minimum twenty (20) year period for peak demand and energy usage forecasts.
- (6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following:
 - (A) Total system.
 - (B) Customer classes, rate classes, or both.
 - (C) Firm wholesale power sales.
- (7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.
- (8) Justification for the selected forecasting methodology.
- (9) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data, such as described in subdivision 4(10) of this rule.
- (b) In providing at least three (3) alternative forecasts of peak demand and energy usage the utility shall include high, low, and most probable peak demand and energy use forecasts to establish plausible risk boundaries as well as a forecast that is deemed by the utility, with stakeholder input, to be most likely based on alternative assumptions such as:
 - (1) Rate of change in population.
 - (2) Economic activity.
 - (3) Fuel prices, including competition.
 - (4) Price elasticity.
 - (5) Penetration of new technology.
 - (6) Demographic changes in population.
 - (7) Customer usage.
 - (8) Changes in technology.
 - (9) Behavioral factors affecting customer consumption.
 - (10) State and federal energy policies.
 - (11) State and federal environmental policies.
- (c) Utilities shall include a discussion of the potential changes under consideration to improve the data quality, tools, analysis as part of the on-going efforts to improve the credibility of the load forecasting process. *(Indiana Utility Regulatory Commission; 170 IAC 4-7-5; filed Aug 31, 1995, 9:00 a.m.: 19 IR 21; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA)*

SECTION 12. 170 IAC 4-7-6 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-6 Resource assessment

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 6. (a) In describing its existing electric power resources, the utility must include in its IRP the following information:

- (1) The net ~~dependable~~ generating capacity of the system and each generating unit.
- (2) The expected changes to existing generating capacity, including the following:

- (A) Retirements.
 - (B) Deratings.
 - (C) Plant life extensions.
 - (D) Repowering.
 - (E) Refurbishment.
- (3) A fuel price forecast by generating unit.
- (4) The significant environmental effects, including:
- (A) air emissions;
 - (B) solid waste disposal;
 - (C) hazardous waste; and
 - (D) subsequent disposal; and
 - (E) water consumption and discharge;
- at each existing fossil fueled generating unit.
- (5) An analysis of the existing utility transmission system that includes the following:
- (A) An evaluation of the adequacy to support load growth and expected power transfers.
 - (B) An evaluation of the supply-side resource potential of actions to reduce transmission losses, congestion, and energy costs.
 - (C) An evaluation of the potential impact of demand-side resources on the transmission network.
 - (D) An assessment of the transmission component of avoided cost.
- (6) A discussion of DSM programs and their estimated impact on the utility's historical and forecasted peak demand and energy.

The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall be provided for each year of the future planning period.

(b) In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements:

- (1) Innovative rate design as a resource in meeting future electric service requirements.
- (2) Demand-side resources, including:
 - Demand response programs, and
 - Energy efficiency programs.

For a demand-side resource identified in the IRP, the utility shall, include the following:

- (A) A description of the program considered.
- (B) The avoided cost projection on an annual basis for the forecast period that accounts for avoided generation, transmission, and distribution system costs. The avoided cost calculation must reflect timing factors specific to programs under consideration such as project life and seasonal operation.
- (C) The customer class or end-use, or both, affected by the program.
- (D) A participant bill impact projection and participation incentive to be provided in the program.
- (E) A projection of the program costs to be borne by the participant.
- (F) Estimated annual and lifetime energy (kWh) and demand (kW) savings per participant for each program.
- (G) The estimated program penetration rate and the basis of the estimate.

(H) The estimated impact of a DSM program on the utility's load, generating capacity, and transmission and distribution requirements.

(I) whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.

(3) Supply-side resources, including: new utility generation using commercially available resources or co-generation; purchase or lease of a non-utility generating facility; direct purchase of capacity, energy or ancillary services from a non-utility resource; and purchase of capacity, energy or ancillary services through a wholesale power purchase.

~~cogeneration;~~

~~non-utility generation;~~

~~commercially available resources; and~~

~~wholesale power purchases.~~

For potential supply-side resources, the utility shall include the following:

(A) Identification and description of the supply-side resource considered, including:

(i) Size (MW).

(ii) Utilized technology and fuel type.

(iii) Additional transmission facilities necessitated by the resource.

(iv) The energy profile of non-dispatchable resources.

(B) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.

(C) An analysis showing that non-dispatchable resources and dispatchable resources have been evaluated on a consistent and comparable basis on their respective levelized cost of energy. (NOTE: THIS LANGUAGE COULD INSTEAD BE INSERTED IN SEC. 8(C)(7), WHICHEVER STAFF DETERMINES TO BE THE MOST APPROPRIATE LOCATION)

(D) If an electric utility has submitted or had a CHOICE Plan approved, pursuant to 170 IAC 17.1, it shall consider and evaluate the impact of that plan in meeting future electric service requirements.

(4) transmission facilities as a resource including:

new projects;

upgrades to transmission facilities;

efficiency improvements; and

smart grid technology.

In analyzing transmission resources, the utility shall include the following:

(A) A description of the timing, types of expansion, and alternative options considered.

(B) The approximate cost of expected expansion and alteration of the transmission network.

(C) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost effective resources.

(D) A description of how:

(i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and

(ii) RTO planning and implementation processes affect the IRP. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-6; filed Aug 31, 1995, 9:00 a.m.: 19 IR 22; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA*)

SECTION 13. 170 IAC 4-7-7 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-7 Selection of resources

Authority: IC 8-1-1-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 7. (a) In order to eliminate nonviable alternatives, a utility shall perform an initial screening of all future resource alternatives listed in subsection 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.

(b) The following information must be provided for a resource selected for further analysis:

(1) A description of significant environmental effects, including the following:

(A) Air emissions.

(B) Solid waste disposal.

(C) Hazardous waste and subsequent disposal.

(D) Water consumption and discharge.

(2) An analysis of how existing and proposed generation facilities conform to the utility-wide plan and the commission analysis to comply with existing and reasonably expected future state and federal environmental regulations, including facility-specific and aggregate compliance options and associated performance and cost impacts.

(c) For each DSM program analyzed under this section, the IRP must include one (1) or more of the following tests to evaluate the cost-effectiveness of the program.

(1) Participant cost test.

(2) Ratepayer impact measure.

(3) Utility cost test.

(4) Total resource cost test.

(5) Other reasonable tests accepted by the commission.

(d) A utility is not required to calculate a test result in a specific format.

(e) For each program in subsection (c), a utility must calculate the net present value of the program's impact over the life cycle of the impact. A utility shall also explain the rationale for choosing the interest rate used in the net present value calculation.

(f) For a test performed under subsection (c), an IRP must:

(1) specify the components of the benefit and the cost for the test; and

(2) identify the equation used to calculate the result.

(g) If a reasonable cost-effectiveness analysis for a program cannot be performed using the tests in subsection (c), because it is difficult to establish an estimate of load impact, such as a generalized information program, the cost-effectiveness tests are not required.

(h) To determine cost-effectiveness, the RIM test must be applied to a load building program. A load building program shall not be considered as an alternative to other resource

options. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-7; filed Aug 31, 1995, 9:00 a.m.: 19 IR 23; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA*)

SECTION 14. 170 IAC 4-7-8 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-8 Resource portfolios

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 8. (a) The utility shall develop candidate resource portfolios from the selection of future resources in section 7 and provide a description of its process for developing its candidate resource portfolios. In selecting the candidate resource portfolios, the utility shall consider the following:

- (1) risk;
- (2) uncertainty;
- (3) regional resources;
- (4) environmental regulations;
- (5) projections for fuel costs;
- (6) load growth uncertainty;
- (7) economic factors; and
- (8) technological change.

(b) With regard to candidate resource portfolios, the IRP must include:

- (1) An analysis of how each candidate resource portfolio performed across a wide range of potential futures.
- (2) The results of testing and rank ordering the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metric(s).
- (3) The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.

(c) From its candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following information:

- (1) A description of the utility's preferred resource portfolio.
- (2) Identification of the variables used.
- (3) Identification of the standards of reliability.
- (4) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio.
- (5) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of the following:
 - (A) safety;
 - (B) reliability
 - (C) risk and uncertainty;
 - (D) cost effectiveness; and
 - (E) customer rate impacts.
- (6) An analysis showing the preferred resource portfolio utilizes, to the extent practical, all economical supply-side resources and demand-side resources as sources of new supply.

- (7) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility including their impacts on the utility's transmission and distribution system for the first ten (10) years of the planning period.
- (8) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following:
- (A) Operating and capital costs of the preferred resource portfolio.
 - (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule.
 - (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio.
 - (D) The utility's ability to finance the preferred resource portfolio.
- (9) A description of how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty, including the following:
- (A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to:
 - (i) environmental and other regulatory compliance;
 - (ii) reasonably anticipated future regulations;
 - (iii) public policy;
 - (iv) fuel prices;
 - (x) operating costs;
 - (v) construction costs;
 - (vi) resource performance;
 - (vii) load requirements;
 - (viii) wholesale electricity and transmission prices;
 - (ix) RTO requirements; and
 - (x) technological progress.
 - (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.
- (10) A description of the utility's workable strategy allowing it to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including the following changes:
- (A) The demand for electric service.
 - (B) The cost of a new supply-side resources or demand-side resources..
 - (C) Regulatory compliance requirements and costs.
 - (D) Changes in wholesale market conditions.
 - (E) Changes in fuel costs.
 - (F) Changes in environmental compliance costs.
 - (G) Changes in technology and associated costs and penetration.
 - (H) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.
- (11) Utilities shall include a discussion of the potential changes under consideration to improve the data quality, tools, and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-8; filed Aug 31, 1995, 9:00 a.m.: 19 IR 23; readopted filed Jul*

11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA)

SECTION 15. 170 IAC 4-7-9 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-9 Short term action plan

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 9. (a) A short term action plan shall be prepared as part of the utility's IRP, and shall cover a three (3) year period beginning with the IRP submitted pursuant to this rule. The short term action plan is a summary of the preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(b)(8), where the utility must take action or incur expenses during the three (3) year period.

(b) The short term action plan must include, but is not limited to, the following:

(1) A description of each resource in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following:

(A) The objective of the preferred resource portfolio.

(B) The criteria for measuring progress toward the objective.

(2) Identification of energy efficiency goals for implementation of energy efficiency that can be produced by reasonably achievable, cost effective plans developed in accordance with 170 IAC 4-8-1 *et seq.* and consistent with the utility's longer resource planning objectives.

(3) The implementation schedule for the preferred resource portfolio.

(4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.

(5) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually transpired. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-9; filed Aug 31, 1995, 9:00 a.m.: 19 IR 24; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA*)

SECTION 16. 170 IAC 4-7-10 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-10 IRP Updates

Authority: IC 8-1-1-3; IC 8-1-8.5-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 10. (a) The utility shall provide the director notice of substantial unexpected changes that occur between IRP submissions.

(b) Upon the request of the commission or its staff, the utility shall provide updated IRP information.

(c) The commission has authority to initiate a formal IRP process based on the updated IRP information. (*Indiana Utility Regulatory Commission; 170 IAC 4-7-10*)

SECTION 17. 170 IAC 4-8-0.5 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-8-0.5 Purpose and Applicability

Authority: IC 8-1-1-3; IC 8-1-8.5-10

Affected: IC 8-1-2-1; IC 8-1-8.5; IC 8-1-13; IC 23-17

Sec. 0.5. (a) The purpose of this rule is to provide the requirements for a utility's energy efficiency plan and requests for cost recovery as set forth in IC 8-1-8.5-10.

(b) This rule applies to utilities as defined in this rule, unless otherwise noted. (*Indiana Utility Regulatory Commission; 170 IAC 4-8-0.5*)

SECTION 18. 170 IAC 4-8-1 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-8-1 Definitions

Authority: IC 8-1-1-3; IC 8-1-8.5-10

Affected: IC 8-1-8.5;

Sec. 1. (a) The definitions in this section apply throughout this rule.

(b) "Allowance for funds used during construction" or "AFUDC" means the cost of borrowed funds used for capital expenditures associated with a utility-sponsored demand response or energy efficiency program, and a reasonable rate on other funds when so used.

(c) "Commission" means the Indiana utility regulatory commission.

(d) "Commission analysis" means the required state energy analysis developed by the commission under IC 8-1-8.5-3.

(e) "Demand-side resource" means one or more demand response programs, energy efficiency programs, or both.

(f) "Demand response" means a reduction in demand for limited intervals of time, such as during peak electricity usage or emergency conditions.

(g) "Demand response program" means a utility program designed to implement demand response.

(h) "End-use" means the light, heat, cooling, refrigeration, motor drive, microwave energy, video or audio signal, computer processing, electrolytic process, or other useful work produced by equipment using electricity.

(i) "Energy efficiency" means reduced energy use for a comparable or improved level of energy service.

(j) "Energy efficiency plan" means a utility's filing with the commission under this rule as required by IC 8-1-8.5-10(g).

(k) "Energy efficiency program" means a utility program designed primarily to implement energy efficiency.

(l) "Energy service" means the light, heat, motor drive, and other service for which a customer purchases electricity from the utility.

(m) "Engineering estimate" means a calculated estimate of energy (kWh) and demand (kW) resulting from demand response program or energy efficiency program, accounting for dynamic interactions between or amount them.

(n) "Evaluation, measurement, and verification" or "EM&V" means the independent application of methods and processes used to assess the performance of one or more energy efficiency programs, demand response programs, or both.

(o) "Free-rider" means a customer who would have implemented demand response or energy efficiency without participating in an energy efficiency program or demand response program, yet participates in a demand response or energy efficiency program and receives an incentive or bonus for participation.

(p) "Gross energy savings" means the change in energy consumption that results directly from the implementation of an energy efficiency program or demand response program.

(q) "Gross demand savings" means the change in demand that results directly from demand response program or energy efficiency program actions taken by program participants regardless of the extent or nature of program influences on their actions.

(r) "Income effect" means the short term and long term change in a customer's energy use that is induced by a change in the amount of disposable income available to the customer.

(s) "Integrated resource plan", or "IRP" means a utility's document submitted to the commission in order to meet the requirements of 170 IAC 4-7.

(t) "Load building" means a program intended to increase electricity consumption without regard to the timing of the increased usage.

(u) "Load retention" means a program intended to induce customers, that have a bona fide option of switching to alternative sources of energy services or customer owned generation, to remain as customers.

(v) "Lost revenue" means the revenue lost, if any, less the variable operating and maintenance costs saved as a result of an energy efficiency program or demand response program.

(w) "Market effects" means the indirect influence of an energy efficiency program or demand response program that results in energy and demand savings that have not been captured in EM&V activities.

(x) "Net demand savings" means the portion of gross demand savings that is attributable to a demand response program or energy efficiency program, including free ridership and spillover.

(y) "Net energy savings" means the portion of gross energy savings that is attributable to an energy efficiency program or demand response program, including free ridership and spillover.

(z) "Program costs" means the direct and indirect costs of an energy efficiency program or demand response program, including, but not limited to, costs associated with EM&V, lost revenues, and financial incentives.

(aa) "Participant cost test" means a cost-effectiveness test that measures the difference between the cost incurred by a program participant and the direct economic benefit received by a program participant.

(bb) "Participation level" means the actual number of customers participating in a specific demand-side program relative to the eligible number of customers available to participate in the program expressed as a percentage or a fraction.

(cc) "Penetration" means the ratio of the number of a specific type of new units installed to the total number of new units installed during a given time.

(dd) "Persistence" means the percentage of energy-saving effectiveness remaining in a particular year compared to the initial year of the measure's installation or implementation. Persistence is a function of the following two (2) factors:

(1) Equipment degradation.

(2) Consumer behavior.

(ee) "Program Participant" means a utility customer participating in a utility-sponsored energy efficiency or demand response program.

(ff) "Ratepayer impact measure test" or "RIM test" is the change in revenue requirement, expressed on a per unit of sale, from the implementation of an energy efficiency program or demand response program.

(gg) "Rebound effect" means a specific effect where a customer responds to a lower relative cost of electric service by purchasing more electricity in the same end-use where an energy efficiency program is concentrated.

(hh) "Resource" means a facility, project, contract, or other mechanism used by a utility to assist in providing electric energy service to the customer.

(ii) "Spillover" means additional reductions in energy consumption or demand by program participants beyond those directly associated with program participation.

(jj) "Supply-side resource" means a resource that provides a supply of electrical energy or capacity, or both, to a utility. A supply-side resource includes the following:

(1) A utility-owned generation capacity addition.

(2) A wholesale power purchase.

(3) A refurbishment or upgrading of an existing utility-owned generating facility.

(4) A cogeneration facility.

(5) A renewable resource technology.

(6) Distributed generation.

(kk) "Total resource cost test" means a cost-effectiveness test that eliminates the distinction between a participant and nonparticipant by analyzing whether a resource is cost-effective based on the total cost and benefit of an energy efficiency program or demand response program, independent of the precise allocation to a shareholder, ratepayer, and participant.

(ll) "Useful life" means the period of time the investment in a measure remains cost-effectively serviceable.

(mm) "Utility" means

(1) a public, municipally owned, or cooperatively owned electric utility; or

(2) a joint agency created under IC 8-1-2.2;

unless the utility is exempt under IC 8-1-8.5-7.

(nn) "Utility cost test" (also known as the revenue requirements test, or program administrator cost test) means a cost-effectiveness test measuring the ratio of the utility benefits to utility costs. (*Indiana Utility Regulatory Commission; 170 IAC 4-8-1; filed Aug 31, 1995, 10:00 a.m.: 19 IR 24; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA*)

SECTION 19. 170 IAC 4-8-2 IS AMENDED TO READ AS FOLLOWS

170 IAC 4-8-2 Energy Efficiency Plan Filing

Authority: IC 8-1-1-3; IC 8-1-8.5-10

Affected: IC 8-1-8.5[C3]

Sec. 2. (a) An electricity supplier shall file a request for approval of an energy efficiency plan not less than one time every three years beginning no later than December 31, 2017.

(b) A utility applying to the commission for approval of its energy efficiency plan shall include the following information with its petition:

(1) A description of each energy efficiency program and demand response program proposed by the utility.

(2) A budget for the energy efficiency plan, including budgets for each energy efficiency program and demand response program.

(3) A cost-benefit analysis as required by IC 8-1-8.5-10(j)(2) using one or more of the following tests:

(A) Participant cost test.

(B) Ratepayer impact measure.

(C) Utility Cost.

(D) Total Resource Cost.

(E) Other reasonable tests accepted by the commission.

A utility is not required to express a test result in a specific format, however, results must include the total costs and total benefits used in each calculation and the benefit-cost ratio for the specific test.

(4) Projected changes in customer consumption of electricity resulting from the implementation of the energy efficiency plan.

(5) A description of how the energy efficiency plan is consistent with the commission analysis.

(6) A description of how the energy efficiency plan is consistent with the utility's IRP, including copies of relevant portions of the utility's most recent IRP.

(7) Identification of any preference to any customer class potentially resulting from implementation of an energy efficiency program or demand response program.

(8) A description of the lost revenues and financial incentives sought to be recovered or received by the utility.

(9) The effect, or potential effect, in both the long term and the short term, of the energy efficiency plan on the electric rates and bills of program participants compared to the electric rates and bills of customers of nonparticipants.

SECTION 20. 170 IAC 4-8-3 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-8-3 Home Energy Efficiency Assistance Programs

Authority: IC 8-1-1-3; IC 8-1-8.5-10

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 3. (a) A utility shall not include a home energy efficiency assistance program for qualified customers offered by a utility, as described in IC 8-1-8.5-10(h), in the cost effectiveness analysis under section 2 of this rule.

(b) The commission shall approve program costs and lost revenues associated with a home energy efficiency assistance program. (*Indiana Utility Regulatory Commission; 170 IAC 4-8-3; filed Aug 31, 1995, 10:00 a.m.: 19 IR 27; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233;*

readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)

SECTION 21. 170 IAC 4-8-4 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-8-4 Evaluation, Measurement and Verification Plan

Authority: IC 8-1-1-3; IC 8-1-8.5-10

Affected: IC 8-1-8.5

Sec. 4. (a) When seeking commission approval for cost recovery, financial incentives, or lost revenue under section 5, section 6, and section 7 of this rule, a utility shall develop and submit to the commission an EM&V plan to assess implementation and quantify the impact on energy and demand of each energy efficiency program and demand response program. The EM&V plan must include the following for each energy efficiency program and demand response program:

- (1) The type and timing of the measurement activity.
- (2) The process used to modify the impact estimate for future planning and design of the program.
- (3) The utility's evaluation procedure. The utility must include information on how it will collect data to determine:
 - (A) load impact;
 - (B) participation level;
 - (C) utility cost and benefits;
 - (D) participant cost and benefits;
 - (E) net energy program savings;
 - (F) useful life; and
 - (G) persistence.
- (4) The actions the utility will take to:
 - (A) optimize market penetration of the program;
 - (B) minimize freeriders; and
 - (C) measure spillover.
- (5) A comparison of usage and demand patterns of similar participant and nonparticipant groups, through the use of customer bill analysis, engineering estimates, end-use meter data, or other methods. The comparison must identify the impacts of program participation on:
 - (A) gross energy
 - (B) gross demand
 - (C) net energy; and
 - (D) net demand.
- (6) A method to measure rebound effect and the income effect for an energy efficiency program and demand response program where the effect may be significant.

(b) In addition to the EM&V plan submitted to the commission under this section, a utility shall submit to the commission and post to the utility's website, annually, a document containing information, data, and results from the utility's EM&V activities, including its load impact evaluation studies.

(Indiana Utility Regulatory Commission; 170 IAC 4-8-4; filed Aug 31, 1995, 10:00

a.m.: 19 IR 27; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)

SECTION 22. 170 IAC 4-8-5 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-8-5 Cost recovery

Authority: IC 8-1-1-3; IC 8-1-8.5-10

Affected: IC 8-1-8.5

Sec. 5. (a) The commission shall approve the recovery of reasonable energy efficiency program costs and may approve the recovery of reasonable demand response program costs on a timely basis through a periodic rate adjustment mechanism.

(b) The commission shall limit the periodic rate adjustment mechanism to the costs incurred in excess of costs that are included in the utility's base rates, if applicable.

(c) Nothing in this rule precludes a utility from requesting or the commission from approving in a rate case the following:

(1) The inclusion of the program costs in the utility's base rates using a balancing account, where appropriate, to reconcile the utility's recovered expenditures. If approved, the commission may limit cost recovery to the utility's actual incurred expenses if the utility is spending less than the costs authorized by the commission for inclusion in the utility's base rates.

(2) The inclusion of the capital cost, with accumulated AFUDC, in the utility's rate base, amortized over a period set by the commission.

(3) The accumulation, with a carrying charge, of the non-capital cost incurred and not otherwise recovered through the utility's base rates or through periodic adjustments in a deferred account to be amortized over a period set by the commission.

(d) Cost recovery of program costs under this section shall continue as determined by the commission provided that the utility maintains satisfactory EM&V activities as specified in section 4 of this rule.

(e) In order to ensure that energy efficiency program and demand response program benefits and costs are allocated between utility shareholders, participants, and nonparticipants in a fair and economical way, the utility must demonstrate to the commission that an incentive paid by the utility to the customer for participating when combined with the reduction in the participant's utility bills:

(1) reflects the net benefit of the energy efficiency or demand response program to the utility and all customers; and

(2) minimizes cross-subsidies between customer groups and between program participants and nonparticipants within a customer group.

(Indiana Utility Regulatory Commission; 170 IAC 4-8-5; filed Aug 31, 1995, 10:00 a.m.: 19 IR 27; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)

SECTION 23. 170 IAC 4-8-6 IS AMENDED TO READ AS FOLLOWS

170 IAC 4-8-6 Lost revenue

Authority: IC 8-1-1-3; IC 8-1-8.5-10
Affected: IC 8-1-8.5

Sec. 6. (a) A utility seeking recovery of lost revenue shall propose for commission review a methodology or process for calculating lost revenue that accounts for following:

- (1) The impact of free-riders.
- (2) Spillover.
- (3) The change in the number of program participants between base rate changes
- (4) A revised estimate of the energy efficiency program's and demand response program's specific load impact resulting from the utility's EM&V activities.

(b) Nothing in this rule precludes a utility from proposing in a rate case an alternative rate design that eliminates the disincentive to pursue an energy efficiency program or demand response program in lieu of recovery of the utility's reasonable lost revenues. If the commission approves a utility's proposed alternative rate design in a manner that eliminates the utility's disincentive to implement an energy efficiency or demand response program, lost revenue recovery shall not be approved. (*Indiana Utility Regulatory Commission; 170 IAC 4-8-6; filed Aug 31, 1995, 10:00 a.m.: 19 IR 28; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA*)

SECTION 24. 170 IAC 4-8-7 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-8-7 Financial incentives

Authority: IC 8-1-1-3; IC 8-1-8.5-10
Affected: IC 8-1-8.5

Sec. 7. (a) A utility may propose a financial incentive based on particular attributes of an energy efficiency program or demand response program and the program's desired results. A financial incentive may include, but is not limited to, the following:

- (1) Granting a utility a percentage share of the net benefit attributable to an energy efficiency program or demand response program.
- (2) Allowing a utility to earn a greater than normal return on equity for a rate based energy efficiency program or demand response program costs.
- (3) Adjusting a utility's overall return on equity in response to quantitative or qualitative evaluation of an energy efficiency program's or demand response program's performance.

(b) The commission may terminate, when appropriate, a financial incentive.

(c) A financial incentive shall not provide an incentive payment for an energy efficiency program or demand response program unless the net kilowatt or kilowatt-hour impact, or both, can be reasonably determined.

(d) Load building and load retention programs are not eligible for performance incentives.

(e) A financial incentive must reflect the value to the utility's customers of the supply-side resource cost avoided or deferred by the utility's energy efficiency program or demand response program minus the incurred utility program costs.

(f) In order to reflect only the energy efficiency and demand impact of an energy efficiency program or demand response program, the financial incentive must exclude the effect of free-riders from the incentive calculation.

(g) A financial incentive may be based on forecasted demand and energy savings until the information on demand and energy savings from the utility's EM&V activities becomes available. (*Indiana Utility Regulatory Commission; 170 IAC 4-8-7; filed Aug 31, 1995, 10:00 a.m.: 19 IR 28; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA*)

SECTION 25. 170 IAC 4-8-8 IS AMENDED TO READ AS FOLLOWS

170 IAC 4-8-8 Impact of demand-side management on small business

Authority: IC 8-1-1-3; IC 8-1-8.5-10Affected: IC 8-1-8.5

Sec. 8. Contemporaneously with the commission's approval of a utility's petition under this rule, the commission shall, under 16 U.S.C. 2621(c)(3)(A) and 16 U.S.C. 2621(c)(3)(B) effective October 23, 1992, do the following:

(1) Consider the impact that implementation of the proposed energy efficiency or demand response program would have on small business.

(2) If necessary, implement a revision to the proposed energy efficiency program or demand response program to assure that utility actions would not provide the utility with an unfair competitive advantage over small business. (*Indiana Utility Regulatory Commission; 170 IAC 4-8-8; filed Aug 31, 1995, 10:00 a.m.: 19 IR 29; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA*)

[CJ4]