Hoosier Environmental Council's Proposed Red-Lines to Draft IRP Rule (April 2012)

TITLE 170 INDIANA UTILITY REGULATORY COMMISSION
Proposed Rule
LSA Document #11-xxx
DIGEST
Amends 170 IAC 4-7 to update the commission's rule requiring electric utilities to prepare and submit integrated resource plans. Effective 30 days after filing with the Publisher.
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SECTION 1. 170 IAC 4-7-0.1 IS ADDED TO READ AS FOLLOWS

ARTICLE 4. ELECTRIC UTILITIES
Rule 7. Guidelines for Electric Utility Integrated Resource Plans

170 IAC 4-7-0.1 Applicability
Authority: IC 8-1-1-3
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. 0.1 (a) To assist the commission in its administration of the Utility Powerplant Construction Law, IC 8-1-8.5, this rule applies to the following electric utilities:
(1) Public investor owned.
(2) Municipally owned.
(3) Cooperatively owned.
(4) A joint agency created under IC 8-1-2.2. An individual member of a joint agency is not required to submit to the commission a separate IRP.
(b) This rule does not apply to a person who is exempt pursuant to IC 8-1-8.5-7.
~~**(c) The following electric utilities are exempt from the public advisory process requirement in section 2.1 of this rule:**~~
~~**(1) Municipally owned.**~~
~~**(2) Cooperatively owned.**~~
(Indiana Utility Regulatory Commission; 170 IAC 4-7-0.1)

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
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) "Acknowledgement" means the determination by commission staff that an IRP is compliant with the procedures and requirements contained within this rule.
(c) "Allowance" or "emission allowance" means the authority to emit one (1) **unit of any air pollutant as specified by a federal or state emission allowance system**.
(d) "Avoided cost" means the amount of fuel, operation, maintenance, purchased power, labor, capital, taxes, and other costs in the production, transmission, distribution and delivery of electric service, not incurred by a utility if an alternative supply or demand-side resource is included in the utility's integrated resource plan.
(e) "Candidate resource portfolio" means a long-term resource mix selected through the utility's portfolio screening process to be further analyzed as necessary to determine the preferred resource portfolio.
(f) "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, in effect November 9, 1978.
(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 facility necessary to conduct the energy produced by the facility to a user located at or near the project site.

(g) "Commission" means the Indiana utility regulatory commission.
(h) "Conservation" means reducing the amount of energy consumed by a customer for a specific end-use. Conservation includes behavior changes such as thermostat setback. Conservation does not include changing the timing of energy use, switching to another fossil fuel source, or increasing off-peak usage.
(i) "Contemporary issues" means any topic that may affect the inputs, methods, or judgment factors in an IRP that is common to all Indiana jurisdictional utilities. Topics may include, but are not limited to, the following types of issues:

(1) Economic.
(2) Financial.
(3) Environmental.
(4) Energy.
(5) Demographic.
(6) Customer.
(7) Methodological.
(8) Regulatory.
(9) Technological.

(j) "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 analysis.
(k) "Demand-side management" or "DSM" means the planning, implementation, and monitoring of a utility activity designed to influence customer use of electricity that produces a desired change in a utility's load shape. DSM includes only an activity that involves deliberate intervention by a utility to alter load shape.

(l) "Demand-side measure" means a particular end-use device, technology, service, or rate design at a targeted customer's premises or a utility's energy delivery system for a specific DSM program.
(m) "Demand-side program" means a utility program designed to implement a demand-side measure.
(n) "Demand-side resource" means a resource that reduces the demand for electrical power or energy by applying a demand-side program to implement one (1) or more demand-side measures.
(o) "Discount rate" means the interest rate used in determining the present value of future cash flows.
(p) "Distributed generation" means electric generation technology that ~~is relatively small in size,~~ provides efficiency, economic, and environmental benefits due to its proximity to ~~and its implementation favors installation near~~ a load center or remote location on the subtransmission or distribution system.
(q) "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.
(r) "Energy efficiency improvement" means reduced fuel or energy use for a comparable level of energy production or service.
(s) "Energy service" means the light, heat, motor drive, and other service for which a customer purchases electricity from the utility.
(t) "Engineering estimate" means an estimate of energy (kWh) and demand (kW) impact resulting from a demand-side measure based on an engineering calculation procedure. An engineering estimate addresses change in energy use of a building or system resulting from installation of a DSM measure. If multiple DSM measures are installed, an engineering estimate accounts for the interactive effect between the DSM measures.
(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, Sept. 2, 2003.
(u) "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.
(v) "Integrated resource plan" or "IRP" means a **document submitted in order to meet the requirements of this rule**.
(w) "Load building" means a program intended to increase electricity consumption without regard to the timing of the increased usage.
(x) "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.
(y) "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.
(z) "Non-utility generator" means a facility for generating electricity that:

(1) is not exclusively owned by a public utility;
(2) operates connected to an electric utility system; and
(3) sells electricity to a utility for resale to retail customers.

(aa) "North American industrial classification system" or "NAICS" means a system developed by the United States Department of Commerce for use in the classification of establishments by type of activity in which engaged, for purposes of facilitating the collection, tabulation, presentation and analysis of data relating to establishments, and for promoting uniformity and comparability in the presentation of statistical data collected by various

agencies of the United States Government, state agencies, trade associations, and private research organizations.

(bb) "Participant" means a utility customer participating in a utility-sponsored DSM program.

(cc) "Participant test" means a cost-effectiveness test that measures the difference between the cost incurred by a participant in a demand-side program and the value received by the participant. A participant's cost includes all costs borne by the participant. A participant's value from a DSM program consists of only the direct economic benefit received by the participant.

(dd) "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.

(ee) "Preferred resource portfolio" means the utility's selected long-term resource mix that safely and reliably meets electric system demand at the lowest reasonable cost by balancing minimization of the present value of utility revenue requirements with cost-effective minimization of associated risks and uncertainties.

(ff) "Present value" means today's value of a future payment, or stream of payments, discounted at some appropriate compound interest or discount rate.

(gg) "Program cost" means all expenses incurred by a utility in a given year for operation of a DSM program whether the cost is capitalized or expensed. An expense includes, but is not limited to, the following:

(1) Administration.
(2) Equipment.
(3) Incentives paid to program participants.
(4) Marketing and advertising.
(5) Monitoring and evaluation.

(hh) "Public **advisory process**" means **the procedures referenced in section 2.1 of this rule in which customers and interested parties have** the opportunity to **participate in the development of the IRP and** comment on a utility's **IRP** prior to the submission of the IRP to the commission.

(ii) "Ratepayer impact measure" or "RIM" test means a cost-effectiveness test which analyzes how a rate for electricity is altered by implementing a DSM program. This test measures the change in a revenue requirement expressed on a per unit of sale basis.

(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 provide electric energy service to the customer.

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

(nn) "Risk metric" means a measure used to gauge the risk associated with a resource portfolio. As applied to the present value of revenue requirement, 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 appliance or equipment to the total number of customers in that class or the total number of similar appliances or 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) "Self-generation" means an electric generation facility primarily for the customer's own use and not for the primary purpose of producing electricity, heat, or steam for sale to or for the public for compensation.
(rr) "Short term action plan" means a schedule of activities and goals developed by a utility to begin efficient implementation of its **preferred resource portfolio**.
(ss) "Smart grid" means use of digital electronics or data, and the associated communications networks, to monitor and control any aspects of the electrical transmission and distribution system from generation to consumption.
(tt) "Supply-side resource" means a resource that provides a supply of electrical energy or capacity, or both, to a utility or its customers. A supply-side resource includes the following:
(1) A utility-owned generation capacity addition.
(2) A wholesale power purchase from another utility or non-utility generator.
(3) A refurbishment or upgrading of an existing utility-owned generating facility.
(4) A cogeneration facility.
(5) A renewable resource technology.
(6) A generation asset sited on customer property.
(uu) "Targeted demand-side management" or "targeted DSM" means a demand-side program designed to defer or eliminate investment in a transmission or distribution facility.
(vv) "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 the program, independent of the precise allocation to a shareholder, ratepayer, and participant.
(ww) "Utility" means:
(1) a public, municipally owned, or cooperatively owned utility; or
(2) a joint agency created under IC 8-1-2.2.
(xx) "Utility cost test" or "revenue requirements test" means a cost-effectiveness test designed to **measure the impact on** the net present value of a utility's revenue requirements.
(xxi) " Waste Energy Recovery" means the recovery of useful energy from exhaust heat, waste gas, or pressure drop in any gas that would otherwise be flared, incinerated, or vented in connection with the industrial, commercial or institutional processes of the utlity's customers.
(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 Procedures and effects of filing integrated resource plans
Authority: IC 8-1-1-3
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, must submit to the commission an IRP that covers at least a 20 year planning horizon consistent with this rule according to the following schedule**:
(1) Duke Energy Indiana, Hoosier Energy Rural Electric Cooperative, Indiana Michigan Power Company, and Indiana Municipal Power Agency on November 1, 2013, and biennially thereafter.
(2) Indianapolis Power and Light Company, Northern Indiana Public Service

Company, Southern Indiana Gas and Electric Company, and Wabash Valley Power Association on November 1, 2014, and biennially thereafter.

Upon request of a utility, the commission's electricity division director may grant an extension of any such submission dates, for good cause shown.

(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, after appropriate commission review, is constructed, purchased, or leased, the utility shall submit to the commission on a biennial basis, an IRP consistent with this rule.

(c) A utility subject to section 0.1 must submit to the commission, on or before the applicable date as specified in subsection (a), the following documents:

(1) The integrated resource plan.

(2) A technical appendix containing supporting documentation.

(3) An IRP summary document as described in section 4(a) of this rule.

(d) The documents listed in subsection (c) shall be submitted electronically to the director of the commission's electricity division.

(e) The commission staff shall notify the utility and interested parties of its determination of whether to:

(1) acknowledge the IRP; or

(2) identify compliance deficiencies.

(f) The commission staff:

(1) shall describe deficient portions of the IRP, if any; and

(2) may otherwise comment on the IRP.

(g) The commission staff may decline to acknowledge the IRP. If the commission staff declines to acknowledge the IRP, a utility may be asked to:

(1) revise and resubmit specified portions of the IRP; or

(2) incorporate such corrections in the subsequent IRP.

The commission staff may issue instructions to correct deficiencies it identifies.

(h) Any resource action shall be consistent with the last acknowledged IRP, including its:

(1) inputs (including data and assumptions);

(2) methods (including models); and

(3) judgment factors (including the rationales used to determine inputs, methods, risk metric(s), and selection of the preferred resource portfolio); unless any discrepancies between the IRP and the resource action are fully explained and justified with supporting evidence, including an updated IRP.

(i) IRP acknowledgement shall not be construed to mean or constitute a finding as to the pre-approval or prior commission authorization of any specific resource action.

(j) The commission may use an IRP or written comments, or both, submitted pursuant to this rule, to assist in the preparation of an analysis of the long range needs for expansion of facilities for the generation of electricity and plan for meeting the future requirements of electricity as required by IC 8-1-8.5. The IRP or written comments, or both, submitted pursuant to this rule **may be used** in the preparation of a staff report in other formally docketed proceedings.

(1) **The following written documents submitted** pursuant to this rule may be admitted as evidence in a formally docketed proceeding before the commission under the Indiana Rules of Evidence:

(A) An IRP.

(B) Written comments submitted to the commission's electricity division director.

(C) Commission staff comments pertaining to an acknowledgement.

(2) The commission shall give such weight as it determines appropriate to any IRP, or written comments submitted to the commission thereon, admitted as evidence in a formally docketed proceeding as provided in **subdivision j(1)** above.

(k) Contemporaneously with the submission of an IRP to the commission, a utility must include the following information:

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

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

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

(B) A statement that the commission invites an interested party to submit written comment on the utility's submitted IRP.

(C) A statement that subsection **(m)** below provides for a **seventy-five (75)** day time period to submit written comments.

A utility is not required to separately notice, as provided in this subsection, each of its customers. A utility may, however, individually notify a business, organization, or a particular customer having a substantial interest in the IRP.

(3) A statement that the utility has served a copy of the IRP on the office of the consumer counselor.

(l) The commission **make a submitted IRP available on its website and to** be viewed, inspected, or copied, in accordance with IC 5-14-3, at the office of the commission at 101 West Washington Street, Suite 1500 E, Indianapolis, Indiana 46204.

(m) A customer or interested party may comment on an IRP submitted to the commission. **Written** comments must:

(1) be received by the commission within **seventy-five (75)** days from the date a utility submits an IRP to the commission.

(2) be submitted to the commission:

(A) as a paper original at the address provided in subsection **(l); or**

(B) electronically to the director of the commission's electricity division;

(3) clearly identify the utility upon which written comments are submitted; and

(4) be ~~served upon~~ the utility.

The **commission's electricity division director** may extend the filing deadline for submitting written comments.

(n) Upon the receipt of written comments of a customer or interested party, a utility may submit to the commission supplemental or response comments. Supplemental or response comments must be:

(1) in writing;

(2) received by the commission within thirty (30) days from the date a customer or interested party submits comments to the commission.

(3) submitted ~~to the commission,~~ **electronically to the director of the commission's electricity division**; and

(4) ~~served~~ ~~upon~~

(A) the customer or interested party who submitted written comments**;** and

(B) the office of the **utility** consumer counselor.

The **commission's electricity division director** may extend the filing deadline for submitting supplemental or response comments.

(o) The **commission's electricity division director** may allow additional written comment periods.

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

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

170 IAC 4-7-2.1 Public advisory process
Authority: IC 8-1-1-3
Affected: IC 8-1-8.5

Sec. 2.1 (a) The utility shall have a public advisory process as outlined in this section.
(b) The utility shall:
(1) provide information to; and
(2) solicit and consider input from;
any interested party in regard to the development of the utility's IRP and related potential resource acquisition issues.
(c) The utility shall consider and respond to all relevant input received.
(d) The utility retains full responsibility for the content of its IRP and is the only entity held accountable in the IRP compliance review.
(e) The public advisory process shall be administered as follows:
(1) The utility shall initiate and convene its own public advisory process. The utility will hold at least:
(A) one introductory meeting; and
(B) one meeting regarding its preferred resource portfolio;
before submittal of its IRP to the commission.
(2) Depending on the level of interest by the public and interested parties in the utility's public advisory process, the utility may hold additional meetings.
(3) The utility shall take reasonable steps:
(A) to notify its customers of its public advisory process; and
(B) provide notification to known interested parties.
(4) The timing of meetings shall be determined by the utility:
(A) to be consistent with its internal IRP development schedule; and
(B) to provide an opportunity for public participation in a timely manner that may affect the outcome of the utility resource planning efforts.
(5) The utility or its designee shall:
(A) chair the participation process;
(B) schedule meetings; and
(C) develop agendas for those meetings.
Participants are allowed to request that items be placed on the agenda of the meetings if they provide adequate notice to the utility.

(6) Topics discussed in the public advisory process shall include, but are not limited to, the following:

(A)The utility's load forecast.

(B) Evaluation of existing resources.

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

(i) associated costs; and

(ii) performance attributes.

(D) Modeling methods.

(E) Modeling inputs.

(F) Treatment of risk and uncertainty.

(G) Rationale for determining the preferred resource portfolio.

(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 Contemporary issues meeting

Authority: IC 8-1-1-3

Affected: IC 8-1-8.5

Sec. 2.2 (a) The commission or its staff may host an annual meeting to help identify contemporary issues and encourage the identification and adoption of best practices to manage such issues.

(b) The meeting may also identify a standardized reporting format.

(c) The agenda of the meeting shall be set by the commission staff that includes input from interested parties and utilities. Utilities and interested parties may petition or informally contact the commission staff to request the inclusion of specific contemporary issues.

(d) The commission staff may issue guidance containing specific contemporary issues to be addressed in a utility's next IRP filing in sufficient time for a utility to incorporate the guidance into its IRP.

(Indiana Utility Regulatory Commission; 170 IAC 4-7-2.2)

SECTION 6. 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

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) **The utility may request a waiver or a variance from a provision of this rule for good cause shown in advance of a filing date.**

(1) The request shall include:

(A) A description of the situation which necessitates the waiver or variance.

(B) Identification of the provision(s) of this rule for which the waiver or variance is requested.

(C) Explanation of the difference between the expected effects of complying with this rule on the utility, its customers, and participants in the public advisory process if the waiver or variance is not granted and the expected effect on such parties if granted.

(D) Explanation of how the waiver or variance is expected to aid or, at the least, not undermine the procedures and requirements of this rule.

(2) The request shall be submitted in sufficient time that the IRP submittal schedule shall not be adversely affected.

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

170 IAC 4-7-4 Methodology and documentation requirements

Authority: IC 8-1-1-3; IC 8-1-8.5
Affected: IC 8-1; IC 8-1.5

Sec. 4. **(a) The utility shall provide an IRP summary document that communicates core IRP concepts and results to non-technical audiences.**

(1) The summary shall provide a brief description of the utility's existing resources, preferred resource portfolio, short term action plan, key factors influencing the preferred resource portfolio and short term action plan, and any additional details the commission staff may request in advance. The summary shall describe, in simple terms, the IRP public advisory process, if applicable, and core IRP concepts, including resource types and load characteristics.

(2) The utility shall utilize a reader-friendly format that includes graphical presentation of the data in a manner that makes it understandable to a nontechnical audience.

(3) The utility shall make this document easily accessible on its website.

(b) An IRP must include **the following:**

(1) A discussion of the:

(A) inputs;

(B) methods; and

(C) definitions;

used in developing the IRP.

(2) The data sets, including data sources, used to establish base and alternative forecasts. A third party data source may be presented in the form of a reference. The reference must include the source title, author, publishing address, date, and page number of relevant data. The data sets must include an explanation for adjustments. The data must be provided on electronic media, and may be submitted as a file separate from the IRP, or as specified by the commission.

(3) A description of the utility's effort to develop and maintain, by customer class, rate class, **NAICS** code, and end-use, a data base of electricity consumption patterns. The data base 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.

(4) 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.
(5) A discussion of customer self-generation within the service territory and the potential effects on generation, transmission, and distribution planning and load forecasting.
(6) A complete discussion of the alternative forecast scenarios developed and analyzed, including a justification of the assumptions and modeling variables used in each scenario.
(7) A description of the fuel inventory and procurement planning practices, including the rationale, used in the development of the utility's **IRP**.
(8) A description of the emission allowance inventory and procurement practices **for any air emission regulated through an emission allowance system**, including the rationale, used in the development of the utility's **IRP**.
(9) A description of the generation expansion planning criteria used in developing the IRP. The description must fully explain the basis for the criteria selected, including an analysis and rationale for the level of system wide generation reliability assumed in the IRP.
(10) FERC Form 715
(11) **A brief description and discussion within the body of the IRP focusing on the utility's Indiana jurisdictional facilities with regard to the following components of FERC Form 715:**

(A) 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. The simulation must include the capability of its transmission system to withstand the impact under N-1 contingency
(C) Reliability criteria for transmission planning as well as the assessment practice used. The information and discussion must include the limits set of its transmission use, its assessment practices developed through experience and study, and certain operating restrictions and limitations particular to it.
(D) Various aspects of any joint transmission system, ownership, and operations and maintenance responsibilities as prescribed in the terms of the ownership, operation, maintenance, and license agreement.

(12) Applicable transmission maps**, including the utility's generating stations, substations, and interconnection ties**.
(13) **The IRP shall utilize appropriate contemporary methods, including a description of the following:**

(A) Model structure and an evaluation of model performance in comparison to other available models.
(B) The utility's effort to develop and improve the methodology and inputs fo its:

(i) forecast;
(ii) cost estimates;
(iii) treatment of risk and uncertainty; and
(iv) evaluating a resource (supply-side or demand-side) alternative's contribution to system wide reliability. The measure of system wide reliability must cover the reliability of the entire system, including:

(AA) transmission;
(BB) distribution; and

(CC) generation.

(14) 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. Avoided cost shall 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, and transmission and distribution operation and maintenance.

(15) The actual demand for all hours of the most recent historical year available**, which shall be submitted electronically and may be a separate file from the IRP**. For purposes of comparison, a utility must maintain three (3) years of hourly data and the corresponding dispatch logs.

(16) ~~Publicly owned utilities~~ shall provide a summary of ~~the utility's~~:

(A) public **advisory process;**

(B) key issues discussed; and

(C) how they were addressed by the utility.

(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 8. 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

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

Sec. 5. (a) An electric utility subject to this rule shall prepare an analysis of historical and forecasted levels of peak demand and energy usage which includes the following:

(1) An historical and projected analysis of a variety of load shapes, including, but not limited to, the following:

(A) Annual load shapes.

(B) Seasonal load shapes.

(C) Monthly load shapes.

(D) Selected weekly and daily load shapes. Daily load shapes shall include, at a minimum, summer and winter peak days and a typical weekday and weekend day.

(2) Historical and projected load shapes shall be disaggregated, to the extent possible, by customer class, interruptible load, and end-use and demand-side management program.

(3) Disaggregation of historical data and forecasts by customer class, interruptible load, and end-use where information permits.

(4) The use and reporting of actual and weather normalized energy and demand levels.

(5) A discussion of all methods and processes used to normalize for weather.

(6) A **minimum** twenty (20) year period for energy and demand forecasts.

(7) An evaluation of the performance of energy and demand forecasts for the previous ten (10) years, including, but not limited to, the following:

(A) Total system.

(B) Customer classes or rate classes, or both.

(C) Firm wholesale power sales.

(8) **Justification for the selected forecasting methodology and why it is consistent with contemporary methods that best meet the requirements of this rule.**

(9) For purposes of **subdivisions (1) and (2)**, a utility may use utility specific data or more generic data, such as, but not limited to, the types of data described in section **4(b)(2)** of this rule.

(b) A utility shall provide at least three (3) alternative forecasts of peak demand and energy usage **consistent with contemporary methods that best meet the requirements of this rule**. At a minimum, the utility shall include high, low, and most probable energy and peak demand forecasts based on combinations of alternative assumptions such as:

(1) Rate of change in population.

(2) Economic activity.

(3) Fuel prices.

(4) Changes in technology.

(5) Behavioral factors affecting customer consumption.

(6) State and federal energy policies.

(7) State and federal environmental policies.

(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 9. 170 IAC 4-7-6 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-6 Resource assessment

Authority: IC 8-1-1-3

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

Sec. 6. (a**The utility shall consider an existing resource as a resource alternative in meeting future electric service requirements.**

(b) The utility shall provide a description of the utility's **existing** electric power resources that must include, at a minimum, 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, but not limited to, 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;

(E) external water consumption and discharge;

at each existing fossil fueled generating unit.

(5) The scheduled power import and export transactions, both firm and nonfirm, as well as cogeneration and non-utility production expected to be available for purchase by the utility.

(6) An analysis of the existing utility transmission system that includes the following:

(A) An evaluation of the adequacy to support load growth and long term power purchases and sales.

(B) An evaluation of the supply-side resource potential of actions to reduce transmission losses.

(C) An evaluation of the potential impact of demand-side resources on the transmission network.

(D) An evaluation of the potential impact of cogeneration and waste energy recovery on the transmission network.

(D) An assessment of the transmission component of avoided cost.

(7) A discussion of demand-side programs, including existing company-sponsored and government-sponsored or mandated energy conservation or load management programs available in the utility's service area and the estimated impact of those programs on the utility's historical and forecasted peak demand and energy.

(8) A discussion of existing cogeneration and waste energy recovery within the utility's service territory, and the estimated impact of these facilities and operations on the utility's historical and forecasted peak demand and energy.

The information listed above in subdivision (a)(1) through subdivision (a)(5) and in subdivisions (a)~~(7)~~ (8) shall also be provided for each year of the planning period.

(~~b~~c) ~~An electric utility shall consider alternative methods of meeting future demand for electric service.~~ A utility must consider a demand-side resource, including innovative rate design, as a source of new supply in meeting future electric service requirements. The utility shall consider a comprehensive array of demand-side measures that provide an opportunity for all ratepayers to participate in DSM, including low-income residential ratepayers. For a utility sponsored program identified as a potential demand-side resource, the utility's **IRP** shall, at a minimum, include the following:

(1) A description of the demand-side program considered.

(2) A detailed account of utility strategies designed to capture lost opportunities.

(3) 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 resources under consideration such as project life and seasonal operation.

(4) The customer class or end-use, or both, affected by the program.

(5) A participant bill reduction projection and participation incentive to be provided in the program.

(6) A projection of the program cost to be borne by the participant.

(7) Estimated energy (kWh) and demand (kW) savings per participant for each program.

(8) The estimated program penetration rate and the basis of the estimate.

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

(d) A utility must consider cogeneration and waste energy recovery at the sites and operations of its industrial, commercial, and institutional customers as a potential resource capable of deferring the need for new electric generating capacity. Such consideration shall include at a minimum:

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1. An inventory of its industrial, commercial, and institutional customers identifying those facilities and operations that may provide the potential for technologically reliable and cost-effective cogeneration or waste energy recovery.
2. An assessment of the potential energy and capacity that maybe available from the development of cogeneration and waste energy recovery at these customer facilities.
3. A description of the utility's rates, rate design, rules, regulations and policies affecting the development of cogeneration and waste energy recovery at these customer facilities, including but not limited to: interconnection standards and rules, and rates and rate design for stand-by, maintenance, back-up and supplemental power.
4. A description of the potential impact of the development cogeneration and waste energy recovery on the utility's revenues and ability to meet its revenue requirements.
5. A description of the impact of the development of cogeneration and waste energy recovery upon other customer classes, including rates and the reliability of service.
6. A description of the potential to relieve any existing constraints, or to defer additional investment in the utility's transmission and distribution facilities.
7. An estimated reduction in the emission levels of criteria, hazardous,and greenhouse gas air pollutants associated with the utility's estimated potential for cogeneration and waste energy recovery at the facilities of its industrial, commercial, and institutional customers.
8. A description of all federal, state, and local financial, regulatory, and technical assistance available to the utility or its customers for the development of cogeneration and waste energy recovery.

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(c) A utility shall consider **a range of** supply-side resources**, including those expected to become commercially available over the planning horizon,** as an alternative in meeting future electric service requirements. The utility's **IRP** shall include, at a minimum, the following:

(1) Identify and describe the resource considered, including the following:

(A) Size (MW).

(B) Utilized technology and fuel type.

(C) Additional transmission facilities necessitated by the resource.

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

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(d) A utility shall **consider new or upgraded** transmission and distribution facilities **as a resource in meeting future electric service requirements, including new projects, efficiency improvements, and smart grid resources.** The **IRP** shall, at a minimum, include the following:

(1) An analysis of transmission network capability to reliably support the loads and resources placed upon the network.

(2) A list of the principal criteria upon which the design of the transmission network is based. Include an explanation of the principal criteria and their significance in identifying the need for and selecting transmission facilities.

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

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

(5) A description of how the IRP accounts for the value of new or upgraded transmission facilities for making additional purchases and sales and accessing geographically constrained resources.

(6) A description of how:

(A) IRP data and information are used in the planning and implementation processes of the RTO of which the utility is a member; and

(B) RTO planning and implementation processes are used in and 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 10. 170 IAC 4-7-7 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-7 Selection of future 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 sections 6(b) through **6(~~d~~f)** 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, but not limited to, a resource summary table. The following information must be provided for a resource selected for further analysis:**

(1) Significant environmental effects, including the following:

(A) Air emissions

(B) Solid waste disposal.

(C) Hazardous waste and subsequent disposal.

(D) External water consumption and discharge.

(2) An analysis of how existing and proposed generation facility conforms to the utility-wide plan to comply with existing and reasonably expected future state and federal environmental regulations.

(A) Facility-specific and aggregate compliance options and associated performance and cost impacts.

(B) Run scenarios with different potential requirements of any potential environmental regulation.

(b) ~~Integrated resource planning includes one (1) or more tests used to evaluate the cost-effectiveness of a demand-side resource option.~~ A cost-benefit analysis must be performed using the following tests except as provided under subsection (e):

(1) Participant.

(2) Ratepayer impact measure (RIM).

(3) Utility cost (UC).

(4) Total resource cost (TRC).

(5) Other reasonable tests accepted by the commission.

(c) A utility is not required to express a test result in a specific format. However, a utility must, in all cases, calculate the net present value of the program impact over the life cycle of the impact. A utility shall also explain the rationale for choosing the discount rate used in the test.

(d) A utility is required to:

(1) specify the components of the benefit and the cost for each of the major tests; and

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

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

(f) 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 11. 170 IAC 4-7-8 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-8 Resource integration
Authority: IC 8-1-1-3
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.**
(b) From its candidate resource portfolios, a utility shall select a **preferred resource portfolio and** provide, at a minimum, the following information:

(1) Describe the utility's **preferred resource portfolio**.
(2) Identify the variables, standards of reliability, and other assumptions expected to have the greatest effect on the **preferred resource portfolio**.
(3) **Demonstrate that all supply-side and demand-side resource alternatives have been evaluated on a consistent and comparable basis.**
(4) Demonstrate that the **preferred resource portfolio** utilizes, to the extent practical, all economical load management, conservation, technology relying on renewable resources cogeneration, **transmission and distribution,** and energy efficiency improvements as sources of new supply.
(5) Discuss the utility's evaluation of **distributed** generation **and** targeted DSM programs including their impacts, if any, on the utility's transmission and distribution system for the first ten (10) years of the planning period.
(*?*) Discuss the financial impact on the utility of acquiring future resources identified in the utility's **preferred resource portfolio.** The discussion **of the preferred resource portfolio** shall include, where appropriate, the following:

(A) Operating and capital costs.
(B) The average price per kilowatt-hour, **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 impact of **the preferred resource portfolio** on the utility's rate.
(E) The utility's ability to finance the **preferred resource portfolio**.

(6) Demonstrate how the preferred resource portfolio achieves the lowest reasonable cost by balancing cost minimization with cost-effective risk and uncertainty minimization, including the following.

(A) Identification and explanation of assumptions.
(B) Quantification, where possible, of assumed risks and uncertainties, which may include, but are not limited to:

(i) regulatory compliance;
(ii) public policy;
(iii) fuel prices;
(iv) construction costs;
(v) resource performance;

(vi) load requirements;
(vii) wholesale electricity and transmission prices;
(viii) RTO requirements; and
(ix) technological progress.

(C) An analysis of how candidate resource portfolios performed across a wide range of potential futures.

(D) The results of testing and rank ordering the candidate resource portfolios by the present value of revenue requirement and risk metric(s). The present value of revenue requirement shall be stated in total dollars and in dollars per kilowatt-hour delivered, with the discount rate specified.

(E) An assessment of how robustness factored into the selection of the preferred resource portfolio.

(7) Demonstrate, to the extent practicable and reasonable, that the **preferred resource portfolio** incorporates a workable strategy for reacting to unexpected changes. A workable strategy is one that allows the utility to adapt to unexpected circumstances **quickly and appropriately**. Unexpected changes include, but are not limited to, the following:

(A) The demand for electric service.

(B) The cost of a new supply-side or demand-side technology.

(C) **Regulatory compliance requirements and costs.**

(D) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.

(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 12. 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
Affected: IC 8-1-8.5; IC 8-1.5

Sec. 9. A short term action plan shall be prepared as part of the utility's IRP and shall cover each of the **three (3)** years 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** where the utility must take action or incur expenses during the **three (3)** year period. 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 and its workable strategy** 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 and its workable strategy**.

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

(2) The implementation schedule for the **preferred resource portfolio and its workable strategy**

(3) A ~~budget~~ **with a confidence range** ~~for the cost to be incurred~~ for each resource or program ~~**and expected system impacts**~~.

(4) 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 13. 170 IAC 4-7-10 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-10 Updates
Authority: IC 8-1-1-3
Affected: IC 8-1-8.5; IC 8-1.5

Sec. 10. (a) The utility may provide an IRP update if substantial unexpected changes occur.
(b) Upon the request of the commission or its staff, the utility shall provide the requested updated IRP information.
(c) The utility shall report its implementation progress between IRP filings in a manner to be specified by the Commission or its staff.
(Indiana Utility Regulatory Commission; 170 IAC 4-7-10)