STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

INTEGRATED RESOURCE PLANNING RULE DEVELOPMENT
2011 PRE-RULEMAKING PROCESS

[PRE-RM 11-07]

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR'S RESPONSES TO COMMISSION QUESTIONS CONCERNING INDIANA'S INTEGRATED RESOURCE PLANNING ("IRP") PROCESS AND REQUIRED IRP REPORTS

A. Purpose, Value, and Usefulness of IRPs

1. What have the purposes, uses, and value of the IRPs been to date?

IRPs have been used for a number of purposes, including reliability, supply, and demand-side planning. The process also requires utilities to assess different economic, environmental and regulatory options to strike a good balance between future generation costs and other factors, such as, energy efficiency, reliability, environmental responsibilities, and competitive pricing for customers.

The OUCC also relies on IRPs as a baseline reference in analyzing CPCN petitions and other types of proceedings where generation capacity and/or the cost of generation are at issue.

2. What should the purposes, uses, and value of the IRPs be? How can the value and usefulness be enhanced?

The OUCC does not envision any new uses or additional purposes. The IRPs will continue to be used by utilities for planning purposes; by the Commission to monitor adequacy and reliability of supply; and by the OUCC as a high-level baseline point of reference when reviewing new CPCN petitions.

B. Ideal Relationships for Various Requirements and Processes

1. **Consider, as a minimum, the IRP, CPCN, DSM, RTO, Summer Preparedness reviews and VCEPS requirements. What should be the relationship between the IRP and these or other processes?**

DSM, VCEPs and CPCN Petitions – These proceedings will provide some of the inputs used in the IRP model.

RTO – The role of RTOs in monitoring adequacy of transmission facilities on a regional basis might eliminate the need to address transmission issues in IRPs.

Summer Preparedness – If the Commission adopts the OUCC's suggestion that utilities file extensive annual updates, as required in states, such as North Carolina, efforts could be made to address summer reliability issues in IRPs and annual updates, without requiring separate reports and presentations on summer reliability preparedness. *(See attached copy of North Carolina's IRP Rule R8-60(h).)*

2. **What recommendations do you have to improve the harmonizing of these requirements and the leveraging of efforts?**

OUCC would defer to utilities' input regarding areas that can be utilized across various reporting mechanisms and suggestions for rearranging the process while still meeting requirements. OUCC supports further efforts to streamline processes for all parties.

C. COMPLIANCE REVIEW

1. **IURC Presentation.**

[No response required.]

2. **Should there be any change to the existing comment and review process? If so, what changes should be made and what would be the value of the change?**

To facilitate review, the OUCC recommends that the Commission provide a standardized template for all utilities to use when submitting IRPs.

3. **What should acknowledgement/acceptance of the IRP by the Commission mean?**

Acknowledgement/acceptance should mean that the IRP submitted contains all elements required. No approval is needed in IRP proceedings.

4. What are the implications for how IRP relates to resource proceedings?

Because the IRP is used at a point in time to project resource needs over the next 20 years, the OUCC uses the IRP as a baseline to compare against later model updates provided by utilities during CPCN proceedings to understand the reasonableness of the request.

D. Enforcement

1. What are possible enforcement mechanisms?

OUCC does not anticipate the need for enforcement proceedings to ensure future compliance with these requirements.

2. What enforcement mechanism is most likely to assure IRPs result in the most robust portfolio for planning, as well as being the basis for other proceedings?

The OUCC has no recommendations for new enforcement mechanisms for the Commission to use in this context. As long as the process is transparent and deficiency letters continue to work, no changes are required. The IRP is simply a snapshot in time that supplies a frame of reference for analysis.

E. Secondary Objectives

1. Should the IRP have secondary objectives?

No.

2. How could the following issues be addressed within the IRP process: reliability, critical infrastructure protection, environmental impact/social cost? Any other factors?

While some consider reliability to be a "secondary" benefit of the IRP process, the OUCC considers reliability to be one of the primary benefits of all IRP studies and reports. The OUCC also recommends inviting the Indiana Department of Homeland Security to address the matter of infrastructure protection, and the Indiana Department of Environmental Management ("IDEM") to comment on matters of environmental impact.

F. Treatment of Resources

1. **How can it be assured that both supply and demand side resources are thoroughly and comprehensively addressed? Should a list of resources to cover be provided in the Rule?**

Because laws and technology changes can occur more frequently than administrative rule updates, the Commission could issue instructions from time-to-time indicating what resources it wishes utilities to consider.

2. **Discuss treatment of resources with particular characteristics. Consider the following questions/issues:**

    a. **There is the intention to treat all resources on cost basis. How should the rule be written so that demand-side resources must be considered on a "consistent and comparable basis" with utility-owned supply-side resources?**

The OUCC's preferred approach before the mandatory DSM requirements established in the generic DSM Order (12/9/09, Cause No. 42693, Phase II) was summarized as follows on page 8 of that Order:

> … [T]he OUCC supports a process whereby the utilities' respective IRP is used to drive DSM decisions… [The OUCC] agreed with the Phase II Report's recommendation that DSM be treated as an output of the IRP modeling process, as opposed to serving as a pre-determined input which serves to reduce the utility's projected load. … [B]oth the IRP and MPS are resources which should be used to inform the DSM decision-making process as part of a utility's least-cost planning strategy.

However, the generic DSM Order mandates a 2% reduction in energy sales by 2019; so in future IRPs, the mandated levels of DSM energy savings will have to be treated as another input for the model, regardless of whether DSM programs are the most cost-effective available option. The

OUCC still expects utilities to select the most cost-effective DSM options necessary to meet the energy savings requirements in the generic DSM Order.

b. Same question as a. for customer-owned generation.

Included as input (not pre-determined) and judged as ranked in the outputs.

Under Indiana utility regulatory law, it does not make sense to suggest that a utility's self-owned generation should be treated as a possible output, rather than as a mandatory component of production in the IRP cost modeling process. Indiana utilities are guaranteed a chance to recover allowed costs, plus a fair rate of return on the fair value of its used and useful utility plant.

c. How should energy storage be treated?

The OUCC has no position at this time, but looks forward to considering and discussing other party's ideas and concerns

d. How should efficiency upgrades and lifetime extension projects be considered for applicable existing resources?

The utilities should continue to consider lifetime extension projects as well as efficiency upgrades within IRPs.

e. What expectations should there be for treating currently pre-commercial technologies that are expected to become commercially viable during the planning horizon?

The OUCC has no position at this time, but looks forward to considering and discussing other party's ideas and concerns.

f. Should and/or how to account for extra system costs (e.g. intermittency, interconnection, and line losses)?

The utilities have indicated that most, if not all, extra system costs are already accounted for in their models. However, if factors are identified that are not already accounted for in the models, the OUCC would support including additional detail.

g. What timescale should resource value be assessed for (e.g. hourly scale might capture differences in time of day values of electric services)?

If the utility is using an hourly dispatch model, the timescale would most likely be sufficient. However, the OUCC looks forward to hearing other interested parties' comments and concerns before finalizing its position.

G. <u>Risk and Uncertainty</u>

1. Presentation by IURC: Trends in the treatment of cost uncertainty

(No response is required.)

2. What uncertainties should be accounted for via risk analysis and scenario planning?

Utilities should continue to determine which scenarios are most important for inclusion in their own IRP submissions. However, the Commission could also issue a uniform set of additional inputs/scenarios in advance, to be addressed by the utilities in the IRP modeling process.

3. What minimum standards/methods should be in the Rule?

The OUCC is unclear on what information the Commission is requesting.

4. How has risk and uncertainty been treated in previous IRPs? (For example, sensitivity, scenario analysis, probabilistic…)

The OUCC defers to the utilities to address the above issues in their IRPs.

5. How should risk and uncertainty be treated in future IRPs?

In addition to the scenarios the utilities currently model, the OUCC recommends that the IURC provide specific additional scenarios and assumptions, as needed, to be applied consistently across all utilities.

H. Important Impacts

1. What 20% of IRP elements have 80% of the results impact?

This will vary by utility, based on current portfolio and changing circumstances.

I. Incremental Review

1. What is the value of incremental, informal review (by IRP development stage) as opposed to relying only on final formal review?

The OUCC sees greatest value in reviewing the analysis in its entirety.

J. Updates, Additions, Deletions, Clarifications

1. Requirements that should be changed due to utilities' involvements in RTO's

There is nothing in the existing rule regarding RTO involvement. The OUCC believes RTOs should be invited to participate and comment on IRPs, to the extent they are interested in doing so.

Given RTOs' role in transmission planning, utilities should be permitted to include copies of FERC Form 715 *Annual Transmission Planning Evaluation Reports* in their IRPs, instead of requiring them to prepare an additional, separate report.

2. Definitions to be added, deleted, modified

In the OUCC 2010 comments, the OUCC recommends changing the term "dispersed generation" to "distributed generation."

The OUCC also recommended adding the term "integrated resource plan" to 170 IAC 4-7-1(s).

3. Planning horizon of 20 years

The 20-year planning horizon is adequate.

4. **Environmental reporting requirements (e.g. the aggregate and incremental change in emission profiles between the preferred and alternative portfolios and current levels)**

The OUCC recommends the Commission not impose new reporting requirements, but rather rely on existing reports if additional data is needed.

5. **Explanation of differences between the last short term action plan and actual**

Deviations from the action plans in the last IRP should be explained.

6. **Need to provide spreadsheets and data bases in formats that allow data to be manipulated to run cases based on different combinations of input values.**

None required for IRPs; however, OUCC may ask utilities to model additional scenarios in CPCN proceedings.

7. **Discussion of select contingency portfolios based on key factors that can change quickly.**

The OUCC does not see the value in complicating the IRP with yet-to-be-known variables.

8. **Rule requirements that need to be clarified**

The OUCC has no additional suggestions at this time.

9. **Other substantive requirements**

Possible revisions to the rule as a result of CHOICE (IC 8-1-37).

K. <u>Deliverables and Format</u>

1. **How and to what extent should the IRP be standardized for ease of development, review, and understanding, including presentation of results?**

See OUCC's response to Question C2 above.

2. **How to make the IRP more concise and to the point?**

The OUCC recommends that the Commission publish instructions or hold a technical conference for the purpose of explaining the level of detail the Commission is looking for in IRP filings.

3. **Discuss need for a less technical summary of IRP results, as a useful communication tool (Refer to APS Resource Plan summary)**

The utilities provide a concise overview of their IRPs in the "Executive Summary" sections.

4. **How to make IRPs more available to stakeholders, the public, and interested parties?**

The OUCC recommends that public portions of IRPs be made accessible to interested stakeholders and to the general public via links on each utility's and IURC and possibly OUCC's websites.

L. STAKEHOLDER/PUBLIC PARTICIPATION PROCESS

1. **Presentation by IURC: Stakeholder Public Participation Process**
   -See also this link to the PNM (New Mexico) IRP site: http://www.pnm.com/regulatory/irp.htm

(No response required.)

2. **What role should the public and stakeholders have in the IRP process? (For example, advisory, consensus-building, etc.)**

The current IRP rule process provides the opportunity for public comment, and appears to be sufficient. Commission may also consider a technical conference after the IRP comments are filed where utilities could answer questions, ask questions of commenters, explain points that were not understood, and provide other information, as needed.

3. **What are pros and cons of such a stakeholder process?**

Pros:

- Transparency in the decision-making process
- Allows for open dialogue
- Educational opportunity

Cons:

- Resource intensive
- Could complicate the IRP process and delay completion
- Could increase regulatory costs recovered from ratepayers
- Might not be possible to achieve consensus
- Could generate misunderstandings regarding the public's role in the IRP planning process

4. **What challenges does such a process bring?**

- The inability to share confidential information with public may create perceived barriers.
- Logistics
- Highly technical subject matter
- Voluminous material to review and discuss
- Potential for low attendance (*cf.* public field hearings)
- Also see list of "Cons" above.

5. **Who should administer the process?**

OUCC has no comment at this time.

6. **How would a utility set up such a process?**

Utilities could emulate the format used for the Commission's IRP technical conferences for the public stakeholder sessions, or use another facilitator-led format.

7. **Should meetings be open to the public at large or limited to a stakeholder team?**

If the desire is to make the process fully transparent, the sessions should be open to all customers and other interested parties.

8. **Should any IRP-conducting entities be exempted from such a process?**

All utilities and other entities required to file IRPs should be subject to the same regulatory process under the IRP rule.

M. PROCEDURAL ISSUES

1. How can data requests be expedited?

The Commission's standard 10-calendar day turn-around time could be used.

2. Suggestions on process for requesting waiver early in IRP development

It is unclear what type of waiver is contemplated here; however, the OUCC would generally discourage the granting of waivers.

3. Suggestions to update and streamline filing process

Consider allowing submissions to be made electronically and service copies provided on discs instead of requiring multiple hard copies of the IRP reports to be made.

Avoid adding more informational requirements to the IRP rule, unless such information is truly needed to complete the analysis required to prepare the IRP (e.g., the need for new data tied to emerging technologies or other notable industry or regulatory changes).

Use other forms or reports already prepared by the utilities for other regulatory purposes, wherever possible.

4. Suggestions on filing and review schedule, e.g., Is there a better filing date? What is a reasonable review timeframe, assuming stakeholders will be involved in IRP development?

If utilities make their submissions in early spring and include the type of data normally presented at the Summer Preparedness Meetings, it could lighten their regulatory compliance workload, while also providing summer preparedness data earlier than currently required. The OUCC still supports a 180-day review period.

5. What are the pros and cons of a filing frequency different from every 2 years? How could an annual update of evolving issues and results relate to filing frequency?

The OUCC believes annual updates would be beneficial, with full IRPs submitted every 2 or 3 years. (See attached copy of North Carolina IRP Rule, which calls for an abbreviated annual update of key data in between the biennial IRP filings.)

Also, if a CPCN petition is filed, the utility should rerun the model and file the update in a sub-docket of its last IRP for ease of future review. If there is a need for additional updates between IRPs due to significant developments, all changes since the last IRP filing should be included in the next model run, which would also be filed in a sub-docket of the utility's last IRP to provide a comprehensive, up-to-date analysis of the utility's energy resources and load.

N. CONTEMPORARY ISSUES AND ANNUAL UPDATE CONCEPTS

1. Presentation by IURC: Contemporary Issues and Annual Update Proposal

(No response required.)

2. What are the pros and cons of instituting the concept of Contemporary Issues?

Pros

- Keep abreast of current trends and cutting edge technological developments
- Opportunity for industry to educate IURC, OUCC and other interested stakeholders on new challenges and any significant anticipated changes that might impact the next IRP filing – whether involving new developments in technology, federal utility regulatory changes, regulatory developments in other states, changes in environmental laws, experience with feed-in tariffs, or other factors impacting future business plans regarding resource adequacy.

Cons

- Ex parte rule constraints
- Need to devote time to meeting preparation as well as attendance
- Could duplicate topics covered at other industry conferences (IEA, INDIEC, etc.)

3. What are the pros and cons of instituting an annual update?

Pros

- More up-to-date information available to analyze CPCN and other petitions
- Improved short-term business planning
- Increased familiarity with data and analysis required in IRPs

Cons

- Additional work
- Additional expense (ultimately recovered from ratepayers)

4. **How can these concepts be harmonized with the annual Summer Preparedness presentations?**

See OUCC Response to Question B1 above.

O. WRAP-UP

1. **What other issues have not yet been addressed?**

None.

2. **Possible action on issues in "parking lot"**

Defer question until next Technical Conference.

3. **Feedback on making 2011 IRPs more available**

See OUCC response to Question K4 above.

4. **Next steps: remaining process and schedule**

(No response required.)

Respectfully submitted,

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Rule R8-60. INTEGRATED RESOURCE PLANNING AND FILINGS.

(a) Purpose. — The purpose of this rule is to implement the provisions of G.S. 62-2(3a) and G.S. 62-110.1 with respect to least cost integrated resource planning by the utilities in North Carolina.

(b) Applicability. — This rule is applicable to Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.; Duke Energy Carolinas, LLC; Virginia Electric and Power Company, d/b/a Dominion North Carolina Power; the North Carolina Electric Membership Corporation; and any individual electric membership corporation to the extent that it is responsible for procurement of any or all of its individual power supply resources.

(c) Integrated Resource Plan. — Each utility shall develop and keep current an integrated resource plan, which incorporates, at a minimum, the following:

(1) a 15-year forecast of native load requirements (including any off-system obligations approved for native load treatment by the Commission) and other system capacity or firm energy obligations extending through at least one summer or winter peak (other system obligations); supply-side (including owned/leased generation capacity and firm purchased power arrangements) and demand-side resources expected to satisfy those loads; and the reserve margin thus produced; and

(2) a comprehensive analysis of all resource options (supply- and demand-side) considered by the utility for satisfaction of native load requirements and other system obligations over the planning period, including those resources chosen by the utility to provide reliable electric utility service at least cost over the planning period.

Each utility shall include an assessment of demand-side management and energy efficiency in its integrated resource plan. G.S. 62-133.9(c). In addition, each utility's consideration of supply-side and demand-side resources, including alternative supply-side energy resources, and the provision of reliable electric utility service at least cost shall appropriately consider and incorporate the utility's obligation to comply with the Renewable Energy and Energy Efficiency Portfolio Standard (REPS). G.S. 62-133.8.

(d) Purchased Power. — As part of its integrated resource planning process, each utility shall assess on an on-going basis the potential benefits of soliciting proposals from wholesale power suppliers and power marketers to supply it with needed capacity.

(e) Alternative Supply-Side Energy Resources. — As part of its integrated resource planning process, each utility shall assess on an on-going basis the potential benefits of reasonably available alternative supply-side energy resource options. Alternative supply-side energy resources include, but are not limited to, hydro, wind, geothermal, solar thermal, solar photovoltaic, municipal solid waste, fuel cells, and biomass.

(f) Demand-Side Management. — As part of its integrated resource planning process, each utility shall assess on an on-going basis programs to promote demand-side management, including costs, benefits, risks, uncertainties, reliability and customer acceptance, where appropriate. For purposes of this rule, demand-side management consists of demand response programs and energy efficiency and conservation programs.

(g) Evaluation of Resource Options. — As part of its integrated resource planning process, each utility shall consider and compare a comprehensive set of potential resource options, including both demand-side and supply-side options, to determine an integrated resource plan that offers the least cost combination (on a long-term basis) of reliable resource options for meeting the anticipated needs of its system. The utility shall analyze potential resource options and combinations of resource options to serve its system needs, taking into account the sensitivity of its analysis to variations in future estimates of peak load, energy requirements, and other significant assumptions, including, but not limited to, the risks associated with wholesale markets, fuel costs, construction/implementation costs, transmission and distribution costs, and costs of complying with environmental regulation. Additionally, the utility's analysis should take into account, as applicable, system operations, environmental impacts, and other qualitative factors.

(h) Filings.

(1) By September 1, 2008, and every two years thereafter, each utility subject to this rule shall file with the Commission its then current integrated resource plan, together with all information required by subsection (i) of this rule. This biennial report shall cover the next succeeding two-year period.

(2) By September 1 of each year in which a biennial report is not required to be filed, an annual report shall be filed with the Commission containing an updated 15-year forecast of the items described in subparagraph (c)(1), as well as significant amendments or revisions to the most recently filed biennial report, including amendments or revisions to the type and size of resources identified, as applicable.

(3) Each biennial and annual report filed shall be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports.

(4) Each biennial and annual report shall include the utility's REPS compliance plan pursuant to Rule R8-67(b).

(5) If a utility considers certain information in its biennial or annual report to be proprietary, confidential, and within the scope of G.S. 132-1.2, the utility may designate the information as "confidential" and file it under seal.

(i) Contents of Reports. — Each utility shall include in each biennial report, revised as applicable in each annual report, the following:

(1) Forecasts of Load, Supply-Side Resources, and Demand-Side Resources. — The forecasts filed by each utility as part of its biennial report shall include descriptions of the methods, models, and assumptions used by the utility to prepare its peak load (MW) and energy sales (MWh) forecasts and the

variables used in the models. In both the biennial and annual reports, the forecasts filed by each utility shall include, at a minimum, the following:

(i) The most recent ten-year history and a forecast of customers by each customer class, the most recent ten-year history and a forecast of energy sales (kWh) by each customer class;

(ii) A tabulation of the utility's forecast for at least a 15-year period, including peak loads for summer and winter seasons of each year, annual energy forecasts, reserve margins, and load duration curves, with and without projected supply- or demand-side resource additions. The tabulation shall also indicate the projected effects of demand response and energy efficiency programs and activities on the forecasted annual energy and peak loads on an annual basis for a 15-year period, and these effects also may be reported as an equivalent generation capacity impact; and

(iii) Where future supply-side resources are required, a description of the type of capacity/resource (base, intermediate, or peaking) that the utility proposes to use to address the forecasted need.

(2) Generating Facilities. — Each utility shall provide the following data for its existing and planned electric generating facilities (including planned additions and retirements, but excluding cogeneration and small power production):

(i) Existing Generation. — The utility shall provide a list of existing units in service, with the information specified below for each listed unit. The information shall be provided for a 15-year period beginning with the year of filing:

a. Type of fuel(s) used;

b. Type of unit (e.g., base, intermediate, or peaking);

c. Location of each existing unit;

d. A list of units to be retired from service with location, capacity and expected date of retirement from the system;

e. A list of units for which there are specific plans for life extension, refurbishment or upgrading. The reporting utility shall also provide the expected (or actual) date removed from service, general location, capacity rating upon return to service, expected return to service date, and a general description of work to be performed; and

f. Other changes to existing generating units that are expected to increase or decrease generation capability of the unit in question by an amount that is plus or minus 10%, or 10 MW, whichever is greater.

(ii) Planned Generation Additions. — Each utility shall provide a list of planned generation additions, the rationale as to why each listed generation addition was selected, and a 15-year projection of the following for each listed addition:

a. Type of fuel(s) used;

b. Type of unit (e.g. baseload, intermediate, peaking);

c. Location of each planned unit to the extent such location has been determined; and

d. Summaries of the analyses supporting any new generation additions included in its 15-year forecast, including its designation as base, intermediate, or peaking capacity.

(iii) Non-Utility Generation. — Each utility shall provide a separate and updated list of all non-utility electric generating facilities in its service areas, including customer-owned and stand-by generating facilities. This list shall include the facility name, location, primary fuel type, and capacity (including its designation as base, intermediate, or peaking capacity). The utility shall also indicate which facilities are included in its total supply of resources. If any of this information is readily accessible in documents already filed with the Commission, the utility may incorporate by reference the document or documents in its report, so long as the utility provides the docket number and the date of filing.

(3) Reserve Margins. — The utility shall provide a calculation and analysis of its winter and summer peak reserve margins over the projected 15-year period. To the extent the margins produced in a given year differ from target reserve margins by plus or minus 3%, the utility shall explain the reasons for the difference.

(4) Wholesale Contracts for the Purchase and Sale of Power.

(i) The utility shall provide a list of firm wholesale purchased power contracts reflected in the biennial report, including the primary fuel type, capacity (including its designation as base, intermediate, or peaking capacity), location, expiration date, and volume of purchases actually made since the last biennial report for each contract.

(ii) The utility shall discuss the results of any Request for Proposals (RFP) for purchased power it has issued since its last biennial report. This discussion shall include a description of each RFP, the number of entities responding to the RFP, the number of proposals received, the terms of the proposals, and an explanation of why the proposals were accepted or rejected.

(iii) The utility shall include a list of the wholesale power sales contracts for the sale of capacity or firm energy for which the utility has committed to sell power during the planning horizon, the identity of each wholesale entity to which the utility has committed itself to sell power during the planning horizon, the number of megawatts (MW) on an annual basis for each contract, the length of each contract, and the type of each contract (e.g., native load priority, firm, etc.).

(5) Transmission Facilities. — Each utility shall include a list of transmission lines and other associated facilities (161 kV or over) which are under construction or for which there are specific plans to be constructed during the planning horizon, including the capacity and voltage levels, location, and

schedules for completion and operation. The utility shall also include a discussion of the adequacy of its transmission system (161 kV and above).

(6) Demand-Side Management. — Each utility shall provide the results of its overall assessment of existing and potential demand-side management programs, including a descriptive summary of each analysis performed or used by the utility in the assessment. The utility also shall provide general information on any changes to the methods and assumptions used in the assessment since its last biennial report.

(i) For demand-side programs available at the time of the report, the utility shall provide the following information for each resource: the type of resource (demand response or energy efficiency); the capacity and energy available in the program; number of customers enrolled in each program; the number of times the utility has called upon the resource; and, where applicable, the capacity reduction realized each time since the previous biennial report. The utility shall also list any demand-side resource it has discontinued since its previous biennial report and the reasons for that discontinuance.

(ii) For demand-side management programs it proposes to implement within the biennium for which the report is filed, the utility shall provide the following information for each resource: the type of resource (demand response and energy efficiency); a description of the new program and the target customer segment; the capacity and energy expected to be available from the program; projected customer acceptance; the date the program will be launched; and the rationale as to why the program was selected.

(iii) For programs evaluated but rejected the utility shall provide the following information for each resource considered: the type of resource (demand response or energy efficiency); a description of the program and the target customer segment; the capacity and energy available from the program; projected customer acceptance; and reasons for the program's rejection.

(iv) For consumer education programs the utility shall provide a comprehensive list of all such programs the utility currently provides to its customers, or proposes to implement within the biennium for which the report is filed, including a description of the program, the target customer segment, and the utility's promotion of the education program. The utility shall also provide a list of any educational program it has discontinued since its last biennial report and the reasons for discontinuance.

(7) Assessment of Alternative Supply-Side Energy Resources. — The utility shall include its current overall assessment of existing and potential alternative supply-side energy resources, including a descriptive summary of each analysis performed or used by the utility in the assessment. The utility shall also provide general information on any changes to the methods and assumptions used in the assessment since its most recent biennial or annual report.

(i) For the currently operational or potential future alternative supply-side energy resources included in each utility's plan, the utility shall provide information on the capacity and energy actually available or projected to be available, as applicable, from the resource. The utility shall also provide this information for any actual or potential alternative supply-side energy resources that have been discontinued from its plan since its last biennial report and the reasons for that discontinuance.

(ii) For alternative supply-side energy resources evaluated but rejected, the utility shall provide the following information for each resource considered: a description of the resource; the potential capacity and energy associated with the resource; and the reasons for the rejection of the resource.

(8) Evaluation of Resource Options. — Each utility shall provide a description and a summary of the results of its analyses of potential resource options and combinations of resource options performed by it pursuant to subsection (g) of this rule to determine its integrated resource plan.

(9) Levelized Busbar Costs. — Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.; Duke Energy Carolinas, LLC; and Virginia Electric and Power Company, d/b/a Dominion North Carolina Power shall provide information on levelized busbar costs for various generation technologies.

(j) Review. — Within 150 days after the filing of each utility's biennial report and within 60 days after the filing of each utility's annual report of amendments or revisions, the Public Staff or any other intervenor may file an integrated resource plan or report of its own as to any utility or may file an evaluation of or comments on the reports filed by the utilities, or both. The Public Staff or any intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. Within 14 days after the filing of initial comments, the parties may file reply comments addressing any substantive or procedural issue raised by any other party. A hearing to address issues raised by the Public Staff or other intervenors may be scheduled at the discretion of the Commission. The scope of any such hearing shall be limited to such issues as identified by the Commission. One or more hearings to receive testimony from the public, as required by law, shall be set at a time and place designated by the Commission.

(NCUC Docket No. E 100, Sub 54, 12/8/88; NCUC Docket No. E-100, Sub 78A, 04/29/98; 08/11/98; NCUC Docket No. M-100, Sub 128, 10/27/99; NCUC Docket No. E-100, Sub 113, 2/29/08; NCUC Docket No. E-100, Sub 113, 3/13/08.)