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Statement of Adoption - Attached Rules

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INVESTIGATION INTO THE DEVELOPMENT OF

RULES CONCERNING INTEGRATED RESOURCE PLANNING

Adopted Date: December 30, 1992

Electric Integrated Resource Planning Rules

of Data.

1.00 Purpose and Scope

1.01 Purpose. The purpose of these rules is to establish a process for the development of integrated resource plans by the Colorado utilities that are subject to these regulations as specified in section 1.02. The process is intended to minimize electric rates and utility revenue requirements to benefit the people and state of Colorado in meeting electric-energy service needs, while recognizing the need to preserve reliable electric service, maintain reasonable electricity prices, and manage risks. This process is also intended to encourage public involvement in the development and review of these plans, and to culminate in review and approval of the plans by the Public Utilities Commission of Colorado ("Commission").

1.02 Scope. This rule shall apply to all jurisdictional electric utilities in the state of Colorado that are required to obtain Certificates of Public Convenience and Necessity ("CPCN") from the Commission, C.R.S. 40-5-101, or are subject to the Commission's regulatory authority over rates and charges, C.R.S. 40-3-101, except cooperative electric associations as defined in C.R.S. 40-9.5-102, and except as otherwise specifically stated in Section 3.01.

2.00 Definitions

2.01 Capacity Factor. The ratio of the net energy produced by a generating facility to the amount of energy that could have been produced if the facility operated continuously at full capacity year-round.

2.02 Cogeneration. The simultaneous or sequential generation of electricity and used and useful thermal energy from a common fuel source, resulting in enhanced thermal efficiency and fewer energy inputs than would be the case if the electricity and useful thermal energy were produced separately. A cogeneration facility that meets the requirements of the Commission's qualifying facility rules, 4 CCR 723-10, may also be a qualifying facility.

2.03 Commission. Colorado Public Utilities Commission.

2.04 Cost-effectiveness Tests. Formulas used to assess the economic attractiveness of demand-side management ("DSM") technologies and programs.

2.05 Cream Skimming. Implementation of DSM programs in which only the most cost-effective or least expensive measures are implemented at a customer's facility, thereby making it uneconomical to return at a later date to that facility to obtain additional cost-effective demand-side resources.

2.06 Customer. Any entity purchasing energy or capacity from a utility on a retail basis.

2.07 Demand-Side Measure. Any hardware, equipment, device, or practice that is installed or instituted resulting in increased energy efficiency, reduced demand, or improved load factor at a customer facility. Demand-side measures can include fuel switching. See 2.20 regarding fuel switching as a Supply-Side Resource.

2.08 Demand-Side Program. A utility-sponsored program, or a program of a third-party selected by the utility to install or institute demand-side measures.

2.09 End-Use. The light, heat, cooling, refrigeration, motor drive, or other useful work produced by equipment that uses electricity or its substitutes.

2.10 Energy Efficiency. The decrease in electricity or gas requirements of participating customers during any selected time period, with energy services held constant.

2.11 Energy Services. The heat, light, motor drive, and other services for which customers of a utility purchase energy from that utility. If equivalent amenity levels or productivity levels are maintained, then energy service is considered constant.

2.12 Externalities. Those environmental and other costs (or benefits) to impacted third parties that result from the generation, transmission, distribution, or reduction in use through efficiency improvements of electricity and that are external to the economic transaction between the supplier (utility) and the retail (ratepayer) customer. The benefits are not paid for, nor are the costs compensated for. Externalities may include, but are not limited to, economic, environmental, health, and safety impacts.

2.13 Free Riders. Those customers who participate in a utility-sponsored DSM program and would have implemented a demand-side measure regardless of the utility-sponsored demand-side program.

2.14 Life-Cycle Costs. All of the costs, including both direct and indirect, associated with the construction, operation, maintenance, fueling, waste disposal, and decommissioning of a supply-side or demand-side resource.

2.15 Lost Opportunities. Situations where cost effective demand side measures could have been installed at a site, but were not, thereby rendering subsequent equal or additional modifications to the site not cost-effective.

2.16 Planning Period. The future period for which a utility develops its integrated resource plan. For purposes of this rule, the planning period is twenty years.

2.17 Qualifying Facility. A co-generator or a small power producer entitled to sell electricity to a utility at wholesale under the authority of the Public Utility Regulatory Policies Act of 1978, 16 USC Sec. 824a-3, et seq., and that meets the requirements of the Commission's qualifying facility rules, 4 CCR 723-19.

2.18 Renewable Resource. Renewable energy resource shall mean any facility, technology, measure, plan or action utilizing a renewable "fuel" source such as wind, solar, biomass, geothermal, waste, or small hydro (as defined in the Public Utility Regulatory Policy Act).

2.19 Resource. Any facility, project, contract, or other mechanism a utility can use to provide energy services to its customers.

2.20 Supply-Side Resource. A resource option that can provide additional electrical energy or capacity to the utility. Supply-side resources include utility-owned generating facilities; electricity purchased from other utilities, cogenerators, qualifying facilities, small power producers, or independent third parties; transmission or distribution improvements; and the life extension or upgrading of existing facilities of the utility through technological improvements, including fuel switching, to more efficiently produce and deliver electricity.

2.21 Technical Potential. The amount of capacity and energy that could be obtained from a demand-side program by the installation and use of the most efficient equipment and technology in each customer facility.

2.22 Thermal Efficiency. With respect to supply-side resources, the total amount of electrical and other useful energy output divided by the total energy input.

2.23 Utility: To the extent applicable in these rules, those entities described in 40-1-103 (1), C.R.S.

3.00 Filing Requirements

3.01 Plan Filing: The utility shall file its first IRP on or before July 1, 1993. Every three years thereafter the utility shall file an original and 15 copies of a 20-year integrated resource plan ("IRP") with the Commission and an application requesting Commission approval of the plan. Whenever cooperative electric associations develop IRPs for other jurisdictional bodies, pursuant to C.R.S. 40-9.5-107 and C.R.S. 40-3-110, such cooperative electric associations shall file an original and 15 copies of the IRP with the commission within 30 days after submission of the plan to such other body. The IRPs filed by the cooperative electric associations shall not be formally approved.

3.02 Required Documentation: The IRP shall consist of the following documents:

(a) An Executive Summary, separately bound and suitable for distribution to the public, which shall be a non-technical description of the preferred plan and alternative plans, and the three-year action plan, all as described in section 6.00; and

(b) A Technical Volume or volumes setting forth in detail, the elements of the preferred plan, the alternative plans, and the action plan. This volume or volumes shall also include the utility's load forecasts, assessments of supply and demand resource alternatives, the supporting data, assumptions, and models used to develop the plans, and a detailed explanation of the utility's efforts in implementing the last plan reviewed by the Commission; and

(c) Technical Appendices containing information enabling the Commission and intervening parties to understand how the preferred plan was developed and to verify the accuracy and consistency of the information used and assumptions made in developing the preferred plan. Technical appendices shall also include documentation and explanations of all data, assumptions, models, and outputs used in development of the preferred and alternative plans, outputs from such models, the results of uncertainty analyses, and citations to all significant sources of information used in the development of the preferred plan.

(d) Annual Progress Reports, submitted one and two years after the submission of the formal Integrated Resource Plan, to keep the Commission and interested parties apprised of the utility's efforts to implement the approved plans and of any changes in circumstances that affect plan implementation. To the extent any changes in assumptions or modelling in the formal plan have occurred, they shall be included in these progress reports.

3.03 Distribution of the Plan. Copies of this plan shall be provided by the utility, at a price not to exceed publication and mailing costs, to parties that intervene in the IRP proceeding. The Staff of the Commission and the Colorado Office of Consumer Counsel will be provided with the utility's plan at no charge.

4.00 Electric Energy and Demand Forecasts

4.01 Forecast Requirements. The utility shall prepare the following energy and demand forecasts for the 20 years starting with the year in which the plan under consideration has been filed:

(a) The total annual jurisdictional sales of electricity by the utility;

(b) Annual sales of energy and coincident peak demand for each major customer class;

(c) Annual sales to other utilities;

(d) Annual intra-utility electricity use;

(e) Annual system losses and the allocation of such losses to the transmission and distribution components of the system; and

(f) Annual system and major customer class load factors and peak demands.

4.02 Modeling for uncertainty. The utility shall develop a range of forecasts of peak demand and energy sales which its system may reasonably be required to serve during the 20-year forecast period. The range shall include at least three levels of expected growth in peak demand and energy sales, based on alternative, internally consistent assumptions about the determinants of peak demand and energy sales, as follows:

(a) A base case scenario, which incorporates assumptions that the utility determines to be most likely;

(b) A high-growth scenario; and

(c) A low-growth scenario.

4.03 Required Detail:

(a) Forecasts of energy sales for residential and commercial customer classes shall be made on the basis of end-use analysis to the extent feasible for IRPs filed through 1996. After 1996, such forecasts shall be made on the basis of end-use analysis.

(b) Forecasts of industrial energy use shall be made on the basis of 2-digit SIC codes and shall be made on the basis of end-use analysis to the extent feasible for IRPs filed through 1996. After 1996, such forecasts shall be made on the basis of end-use analysis.

(c) Forecasts done by other means may be used to check the reliability of the end-use forecasts;

(d) For each 2-digit industrial SIC code and each residential and commercial end-use, the utility shall explain how the effects of the following factors on energy use and peak demand were treated in such forecast:

(1) Changes in energy efficiency and in load factor or peak demand that are expected to occur without utility DSM programs as a result of, for example, government standards, market forces, or programs sponsored by entities besides utilities; and

(2) Changes in energy efficiency and in load

factor or peak demand that are expected to occur as a result of utility DSM programs, including those that maintain or increase loads, implemented prior to the filing of the plan under consideration.

(e) The utility shall maintain as confidential information reflecting historic and forecasted demand and energy use for individual customers. However, when necessary in the IRP proceedings, such information may be disclosed to parties who intervene in accordance with the terms of nondisclosure agreements approved by the Commission and executed by the parties seeking disclosure.

4.04 Historic data. The utility shall:

(a) For each of the ten years immediately preceding the year in which a plan under consideration has been filed, set forth the forecast of peak demand and energy sales made by the utility as well as the actual peak demand and energy sales experienced by the utility in that year; and

(b) Explain, if applicable, why the peak demand and energy sales were different than those that had been forecasted by the utility.

4.05 Description and Justification. The utility shall fully explain, justify, and document the data, assumptions, methodologies, models, determinants, and any other inputs on which it relied to develop its peak demand and energy sales forecasts pursuant to this section as well as the forecasts themselves.

4.06 Format and Graphical Presentation of Data. The utility shall include graphical presentation of the data as shall make the data more understandable to the public, and shall make the numerical data available in such electronic formats as the Commission shall reasonably require.

5.00 Assessment of Resources

5.01 Objective. The utility shall make a thorough and consistent assessment of a wide range of supply- and demand-side resources for potential inclusion in its IRP.

5.02 Supply-Side Resources Investigation. To provide a resource base for use in conducting the assessment required in section 5.01, a utility shall investigate supply-side resources reasonably available to it within the 20-year planning period and the proposed implementation schedules thereof. This investigation shall include a wide range of fuel types (including renewable fuels), technologies, and ownership of resources. Types of resources, among others, that a utility shall investigate include:

(a) Existing power plants and contracts;

(b) Potential changes to existing resources, including, but not limited to, repowering, fuel switching, and life extension of power plants, loss reduction in transmission and distribution systems, regional dispatch of power plants, and improvements in efficiencies including, among other areas, in power-plant thermal efficiency and heat rates;

(c) New utility-owned conventional generation resources, including, but not limited to, fossil fueled, nuclear fueled, or large hydro powered generating stations (as defined in the Public Utility Regulatory Policy Act);

(d) Renewable resources as referenced in 2.18;

(e) Purchases from Qualifying Facilities, including purchases obtainable through bid solicitation programs, if any, approved by the Commission;

(f) Purchases from Independent Power Producers, including purchases obtainable through bid solicitation programs, if any, approved by the Commission;

(g) Purchases from other utilities;

(h) Additional resource-related transmission capacity;

(i) Customer-owned generating capacity that is not a qualifying facility or independent power capacity; and

(j) Resources developed through pooling, wheeling, coordination arrangements, or through other mechanisms not otherwise covered in subsections 5.02(a)-(i).

5.03 Information on Supply-Side Resources. To the extent reasonably available, the utility shall develop and include in its IRP the following information with respect to supply-side resources that it investigates:

(a) A comprehensive analysis of proposed compliance with Title IV of the Clean Air Act Amendments of 1990 including:

(1) Planned operation levels of all facilities

affected under either Phase I or II of Title IV;

(2) The expected emission reductions required under both phases of Title IV;

(3) An assessment of the least-cost means of achieving this reduction, including consideration of:

(i) Fuel-switching (e.g., oil to gas, high-sulphur to low-sulphur coal, and coal to gas);

(ii) Retrofit of pollution control devices;

(iii) Energy-efficiency improvements; and

(iv) Purchase or sale of emission allowances.

(b) With respect to all existing supply-side resources, identification and description, of such resources including:

(1) Name and location;

(2) Rated capacity and net dependable capability;

(3) Equivalent availability factors and capacity factors;

(4) Applicable heat rates;

(5) Specification and description of fuel types, including, with respect to resources using coal, description of the quality of the coal(s) used;

(6) Expected remaining useful life;

(7) Historical fuel prices for the past five years plus projected fuel prices for the next three years including high, base and low estimates and justification thereof;

(8) Historical fixed and variable costs of producing energy for the past five years, and projected fixed and variable costs of producing energy for the next three years; and

(9) Emission rates (expressed in pounds emitted per Kwh generated) of the following substances:

(i) oxides of sulphur;

(ii) oxides of nitrogen and nitrous oxides;

(iii) carbon dioxide;

(iv) carbon monoxide;

(v) volatile organic hydrocarbons;

(vi) particulates;

(vii) methane;

(viii) chlorofluorocarbons and other ozone-depleting substances; and

(ix) air toxics, as defined in Title III of the Clean Air Act.

(10) A description of the impacts on land (including solid-waste disposal) and water resources.

(11) A description of any significant future changes to items (1) through (10) that are presently known.

(c) With respect to existing supply-side resources not owned by the utility, identification and description of these resources including name, fuel type, contract capacity, remaining life of the contract, cost per megawatt and per megawatt-hour and, to the extent available to the filing utility, emission of substances specified in subsection (b)(9)(i)-(ix) and land and water impacts as specified in subsection (b)(10).

(d) Description of the role of existing utility-owned resources as future resources, including a discussion of the potential costs of, and schedules for, repowering, fuel switching, life extension, and improvement in efficiencies including, among other areas, heat rates and thermal efficiency.

(e) With respect to potential new utility-owned generating facilities, identification and description of options for meeting load during the planning period including:

(1) With respect to any new supply-side resource project that a utility has already identified, the utility shall provide information for such resource as specified in subsection 5.03(b) as well as construction cost, construction

schedule, and expected in-service date; and

(2) With respect to other new supply-side resources, the utility shall describe the potential for development of these options by technology and fuel type, addressing the likely costs of construction and production (including a range of projected fuel prices), environmental and other impacts, and availability of these options during the 20-year planning period.

(f) With respect to potential new non-utility-owned generating facilities, identification and description of such options likely to be available during the planning period, including a description of the potential for such facilities by technology and fuel type, addressing the likely amounts of capacity and energy available from such facilities at various assumed prices, the environmental impacts of such facilities, and the availability of such capacity and energy during the 20-year planning period.

(g) With respect to improvements in the efficiency of supply of electricity, identification and description of the potential costs of, and schedules for, such improvements in the 20-year planning period.

(h) With respect to new resource-related transmission-related investments, identification and description of the potential costs of, and schedules for, such investments, including the location of the investment and derivation of the resource capability that such investment is intended to add to the system in the 20-year planning period.

(i) Identification and description of the resource potential and costs of additional power pooling and other forms of coordination with other utilities.

(j) In addition to currently cost-effective renewable resources, analysis and discussion of the potential benefits and costs of a two percent set aside of its annual load growth to be provided by additional renewable resources in such manner and detail that the Commission may approve the additional two percent renewable resource investment if it determines it to be in the public interest to do so.

(k) Analysis of the potential of curtailable and interruptible service offerings to its customers in order to improve system capacity utilization.

(l) When a utility has excess capacity, analysis of how it intends to increase efficiency through management of off-system sales contracts.

5.04 Demand-Side Resource Assessment

(a) The utility shall conduct an assessment of the technical potential for future demand-side measures as a guide for developing comprehensive demand-side programs. The utility shall carry out such assessment for each major customer class and end use.

(b) The utility shall estimate the demand-side resources available for use in developing an integrated resource plan. In the development of such estimates, a utility shall be guided by the following principles:

(1) All cost-effective DSM programs, as defined in sections 5.05 and 5.06 below, shall be included in the estimate for the 20-year planning period;

(2) DSM programs shall contain monitoring and

evaluation components;

(3) The utility's DSM programs shall strive toward the development of a diverse set of DSM programs that encompasses all customer classes, including low-income customers;

(4) The utility's DSM programs shall strive to discourage free-riders;

(5) The utility's DSM programs shall strive to minimize lost-opportunities;

(6) The utility's DSM programs shall strive to avoid cream skimming; and

(7) The utility's DSM programs shall examine the effects of its DSM programs on rates and reliability.

(c) The utility shall provide estimates of participation rates, costs (including program administration as well as measure costs), net and total energy, and load impacts over the 20-year analysis period for each DSM program.

(d) The utility shall provide the information in subpart 5.04(c) for each major rate class.

5.05 Avoided Costs. The utility's avoided cost calculations shall include both the marginal energy and the capacity costs arising from resources for which an alternative supply-side or demand-side resource may be substituted.

(a) The utility's resource plan shall completely explain and document its avoided cost calculations. Avoided costs should be reported annually for the forecast period. Avoided cost calculations should reflect timing factors specific to the resources being considered such as project life and seasonal operation factors.

(b) Avoided costs shall include:

(1) Avoided generating capacity costs adjusted for transmission and distribution (both primary and secondary) losses and reserve margin requirements;

(2) Avoided transmission capacity costs;

(3) Avoided distribution capacity costs;

(4) Avoided operating costs, including fuel, plant operations and maintenance, and transmission/distribution operations and maintenance, adjusted for transmission and distribution (both primary and secondary) losses; and

(5) Net avoided environmental and other externalities as well as other economic impacts as may be established to the satisfaction of the Commission consistent with Section 5.11.

5.06 Assessment of All Demand-Side Resources Through Use of Cost Effectiveness Tests.

(a) The utility shall perform an initial assessment of all demand-side resources assessed pursuant to section 5.04 (a) utilizing the following tests:

(1) Participant Test: This test measures the quantifiable benefits and costs to the customer due to participation in the DSM program. The benefits include rebates from the utility, lower customer bills, and avoided capital and operating costs. The costs include out of pocket expenses paid by the customer and any increases in customer bills from DSM programs or increased customer usage later.

(2) Ratepayer Impact Measure Test: This test measures what happens to customer rates due to changes in utility revenues and operating costs caused by a DSM program. The costs are those associated with DSM program implementation, incentives paid to participants, incentives paid to the utility for DSM, and the net change in utility revenues after loads have changed.

(3) The Utility Cost Test: This test measures the net costs of a DSM program based on the costs incurred by the utility to offer the DSM program and any increased supply costs for periods when load is increased. The benefits are avoided supply costs when there is a load reduction.

(4) Total Resource Cost Test: This test measures the net costs of a DSM program based on both the utility's costs and the costs incurred by the participants. It is a summation of the Ratepayer Impact Measure Test and the Participant Test where the revenue change and the customer incentive terms should match each

other except for differences in the net and gross savings. The benefits are net avoided supply costs.

(b) The utility or an intervenor may supply the Commission with information regarding the assessment of a demand-side resource utilizing the Societal Cost Test. This is an analytical test that is used to identify resources that provide net benefits considering all economic, environmental, and social factors. A resource option is cost-effective under this test when the present value life-cycle benefits exceed the present value life-cycle costs.

(c) The IRP shall include complete documentation of how equity between participants and non-participants was addressed, and how the assessment was performed by the utility for DSM technologies.

5.07 Load Building Programs. The utility shall provide a detailed description of all programs it has, or plans to have, that increase load (including industrial-development and other special rates, as well as other marketing efforts), including the costs of the programs and their effects on electricity use and peak demands. This requirement includes programs that encourage the substitution of the use of electricity for the use of gas, or the substitution of the use of gas for the use of electricity, in meeting the demand for energy services.

5.08 Load Retention Programs. The utility shall provide a detailed description of all programs it has, or plans to have, that retain load, including those intended to prevent bypass through contracts under CRS 40-3-104.3 with a customer expressing the intention to meet all or part of its electric needs by an alternative means.

5.09 Fuel-switching.

(a) The utility that sells both natural gas and electricity shall analyze the costs and benefits of the substitution of natural gas for electricity or vice versa in meeting the demand for energy services.

(b) The analysis required by subsection (a) shall address the following factors:

(1) A statement of the estimated amount of kilowatts, kilowatt-hours, or MCFs to be substituted; and

(2) The impact on equity between electric and gas customers, including changes in electricity and gas prices; and

(3) The impact on utility revenues by such substitution.

5.10 Electricity Pricing. The utility shall explain whether current rate designs for each major customer class are consistent with the utility's IRP. The utility shall also explain whether possible future changes in rate design will facilitate integrated resource planning goals.

5.11 Environmental and Other Impacts. For each resource considered for inclusion in the utility's portfolio of resources to be acquired in the action plan or projected to be acquired in the IRP, the utility shall identify environmental and other impacts of the resource and any other resources considered but not selected. The utility shall show how qualitative consideration of these factors was utilized by the utility in developing its plans.

5.12 Description and Justification. The utility shall fully explain, justify, and document the data, assumptions, methodologies, models, determinants and all other inputs on which it relied to develop the information required by this section. Also, a utility shall fully explain, justify and document the way in which the criteria set forth in section 5.01 et seq. were applied to each resource assessed.

6.00 Development of Integrated Resource Plans

6.01 Development of Integrated Resource Plans. The utility shall develop integrated resource plans and supporting explanation, justification, and documentation for submission to the Commission.

(a) In developing an IRP, the utility shall treat all demand- and supply-side resources consistently and equitably.

(b) Integrated Resource Plans shall be developed pursuant to the following procedure:

(1) Using the resources assessed pursuant to section 5.00 et seq., the utility shall develop plans to meet the need for energy and capacity for each of the demand forecasts established in section 4.02;

(2) The utility shall develop the plans required by 6.01 so that they maximize the positive value of the Total Resource Cost Test. For any demand-side resource included in the plans, the utility shall supply the results of the four tests listed in Section 5.06 (A)

(1)-(4). In developing plans that optimize the Total Resource Cost Test, the utility shall show how externalities have been considered in developing such plans. The utility shall explain, justify, and document the manner in which these plans were developed, including all financial, regulatory and other significant assumptions.

(3) In consultation with the Working Group established in section 7.00, the utility shall develop such additional plans designed to meet different objectives that it deems appropriate.

(4) The utility shall conduct additional analysis to examine the risks and uncertainties associated with meeting the energy service needs in each forecast. Items of risk and uncertainty to be considered include, but are not limited to:

(i) Fuel prices for electricity production and for customer end uses;

(ii) In-service dates of supply and demand resources;

(iii) Unit availability;

(iv) Market penetration rates for, and the cost-effectiveness of, demand-side programs;

(v) Inflation in plant construction costs and the cost of capital;

(vi) Use of risk-adjusted discount rates;

(vii) Availability and cost of purchased power;

(viii) Possible federal or state legislation or regulation;

(ix) New technological developments; and

(x) Unit decommissioning or dismantlement costs.

(5) The utility shall, to the extent feasible, report results on each of the plans it develops with respect to the following criteria:

(i) The expected capital and operating costs of the resource plan and its effect on utility revenue requirements;

(ii) Impact on electricity prices;

(iii) Impact on the environment, including environmental externalities consistent with section 5.11;

(iv) Effects on fuel and technology diversity and other factors affecting the plan's ability to respond to unforeseen changes;

(v) Reliability of the system;

(vi) Impact on the utility's financial condition;

(vii) Impact on the Colorado and local economies, to the extent feasible;

(viii) Use of renewable resources; and

(ix) Sustainability.

6.02 The Preferred Plan. The utility shall develop a preferred plan for submission to the Commission on the basis of the analysis required in section 6.01 and any other analysis which the utility believes to be appropriate. The utility shall fully explain, justify and document the manner in which it developed this preferred plan, including an explanation of how it ensured internal consistency in avoided costs and retail electricity prices. If the utility's preferred plan differs from the plan that minimizes total resource costs in meeting electric-energy service needs, the utility shall explain fully the reasons for its choice of a different resource plan.

6.03 Short-term Action Plan. The utility shall file a short-term action plan that sets forth the steps that it will take to implement the preferred long-run plan prior to the next IRP filing, including proposed budgets for these steps as well as an explanation and justification of the need to take such steps. The action plan shall also present the data collection and analysis activities the utility plans to conduct to improve its resource-planning capabilities. The short-term action plan shall cover each of the three years beginning with the year the plan is filed with the Commission.

6.04 Description and Justification. The utility shall fully explain, justify, and document the data, assumptions, methodologies, models, and any other inputs on which it relied to develop the information required by this section.

7.00 Public Participation

(a) At the time of filing its request to open a docket pursuant to Rule 8.01(a), a Working Group shall be formed and shall consist of representatives of the utility, the Staff of the Commission, the Office of Consumer Counsel, and all other interested parties.

(b) The utility shall afford all interested persons the opportunity to participate fully throughout the development of the utility's IRP.

(c) All meetings of the IRP Working Group shall be open to the persons and parties described in section 7.00 (a) and (b).

(d) Unless otherwise ordered by the Commission, the utility or its designee shall chair the IRP Working Group, schedule meetings, and develop agendas for these meetings.

(e) IRP Working Group meetings shall be scheduled on a periodic basis. The purposes of the IRP Working Group are for the utility to provide information on the status of its plan development and for non-utility parties to provide input to, comments on, and appropriate public dissemination of information regarding the utility's IRP process including assumptions, models, and results. Topics to be discussed at the Working Group meetings include, but are not limited to, the utility's progress in implementing its latest IRP, key assumptions and data used in the planning process, the models and other analytical techniques used by the utility, the results of the plan, and the topics covered in sections 4.00, 5.00, and 6.00 of this rule. In addition, the utility shall run its computer models to develop alternative resource plans based on inputs and assumptions from the Working Group.

(f) The utility shall prepare a summary of the agendas and discussions held during the Working Group meetings. The summaries, as well as the utility's responses to the inputs from the Working Group shall be included in the utility's IRP filing.

(g) The utility shall have the right to require members of the working group to execute nondisclosure agreements to govern proprietary information before disclosing any such information to the members.

8.00 Filing Procedures and Commission Review

8.01 Pre-IRP Filing Procedures.

(a) At least 180 days prior to filing its IRP pursuant to section 3.02, a utility shall file with the Commission a request to open a docket for the purpose of resolving resource planning issues for that utility. Those entities that intervene in this docket shall be known as the "parties".

(b) The utility shall strive to create opportunities for informal discussions between it and the other parties throughout the preparation of its plan, as discussed in section 7.00. At a minimum, a utility shall prepare and provide to the parties a Preliminary Plan, including a preferred plan, an action plan, and alternative plans, at least 90 days prior to filing its IRP pursuant to section 3.02. This Preliminary Plan shall be comprised of the same documents, in draft, as are required to be submitted by section 3.02.

(c) Any party may conduct informal or formal discovery of the utility with respect to the Preliminary Plan, pursuant to the Commission's Rules of Practice and Procedure, except that the time in which the utility shall respond to the discovery requests of the parties shall be 21 days.

(d) Any party shall have a reasonable opportunity to have the utility run the models it uses to develop plans with assumptions specified by such party. The utility shall have an opportunity to schedule any such activities, and to coordinate and limit such requests, so as to manage the burden imposed by this requirement. However, the utility shall not be required to run such models during the 45 day period prior to its IRP filing.

(e) Requests for any information that the utility deems to be privileged shall be governed by a Commission-approved protective agreement which allows limited access and distribution of such information to the parties to the IRP proceeding. This agreement should be developed and filed with the Commission at least 80 days prior to the date on which the utility will file its IRP with the Commission.

8.02 Commission Review of the IRP

(a) The utility shall file an IRP that is complete and reviewable pursuant to these rules. The Commission shall review the plan that is filed under this rule. After this review, the Commission shall determine whether the utility plan is complete and reviewable within 15 days following the filing of the IRP by the utility. If the Commission determines that the IRP is not complete and reviewable, it shall reject the IRP and require that the utility file a new IRP within 90 days of such rejection.

(b) Upon receiving a complete and reviewable IRP, the Commission may hold a hearing. Based upon the evidence of record, as consistent with the purpose of these rules (Section 1.01), the Commission shall render a decision either approving the IRP, approving it in part and rejecting it in part, or rejecting it.

8.03 Effect of Commission Approval on an Electric Utility's Integrated Resource Plan in Future Proceedings

(a) At the time of a proceeding on a utility's request to the Commission for recovery of investment and expenses incurred or approval of certain actions taken pursuant to the conditions set forth in its IRP short term action plan, whether in an advice letter, application, or certificate proceeding, the utility has the burden of going forward to submit prima facie evidence that its actions are or were consistent with its plan.

(b) Upon the utility meeting its initial burden of presenting prima facie evidence of action consistent with the plan, the burden of going forward shall shift to intervenors who wish to challenge the propriety of the utility's actions.

(c) In order to meet the utility prima facie evidence, an intervenor must present evidence that the utility's actions are not or were not consistent with the plan, or due to changed circumstances or other factors, the utility's actions are or were improper, not in the public interest, or resulted or will result in unjust or unreasonable rates.

(d) Upon a showing by an intervenor of the matters set forth in subsection (c), the utility shall have the ultimate burden of proof to show that its actions are or were in compliance with its last Commission approved IRP and are or were appropriate and in the public interest.

(e) The utility proposing certain actions which are inconsistent with its approved short-term action plan shall have the burden of explaining the reasons for the inconsistency and shall demonstrate that its proposed action is in the public interest.

(f) The approval of a utility's IRP by the Commission under the provisions of section 8.02 shall not preclude an independent finding by the Commission which differs from the utility's approved IRP in a subsequent proceeding in which the utility seeks the recovery of revenue for actions taken consistent with its IRP (e.g. rate case review, or application for cost recovery) under C.R.S. 40-3-101 et seq., or the granting of a certificate of public convenience and necessity as required by C.R.S. 40-5-101 et seq.

8.04 Amendment to Approved Plan Outside of Rate or CPCN Proceedings.

The utility may, at any time, file an application to amend an approved IRP. The application shall contain a demonstration of why the utility seeks to amend the approved plan. For good cause shown, the Commission shall institute procedures to determine whether the utility's approved plan should be amended. The Commission shall publish notice of the procedures and shall give reasonable time for interested parties to prepare for them. The Commission may hold a hearing on the application and shall render, within 90 days after the conclusion of any hearing, a decision either approving the amended IRP as consistent with the purposes of these rules (Section 1.01), approving it subject to stated conditions or modifications, approving it in part and rejecting it in part, or rejecting it.

9.00 Waivers

9.01 General Waivers. The utility may file an application for a waiver or variance from a provision or provisions of this rule. Any such application shall demonstrate the basis for the utility's contention that it should be granted a waiver or variance, including documentation regarding the costs and benefits of compliance. For good cause shown and if not contrary to law, the Commission may grant a waiver or variance if the Commission finds that compliance with such provision is impracticable or unreasonable, provided that the plan that the utility will file is likely to otherwise be consistent with the purpose of this rule.

9.02 Small Utility Waiver. Any electric utility with annual electric retail sales in Colorado of less than 1,750 Gwh may request a waiver or variance from a portion or those portions of this rule for which the cost of compliance is likely to exceed the benefits of compliance. In all such cases, the utility seeking the waiver must demonstrate that, if the waiver or variance is granted, its IRP is likely to otherwise be consistent with the purpose of this rule.