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September 28, 2011

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LA PUBLIC SERVICE
COMMISSION

Ms. Terri Lemoine
Records and Recording Division
Louisiana Public Service Commission
Galvez Building, 12th Floor
602 North Fifth Street
Baton Rouge, LA 70821

RE: Docket R-30021: In Re: Development and Implementation of Rules for Integrated Resource Planning for Electric Utilities

Dear Ms. Lemoine:

Attached please find an original and three copies of the Comments Of The Alliance For Affordable Energy on Staff's "Proposed Integrated Resource Planning Rules for Electric Utilities In Louisiana" in the above referenced docket.

Thank you for your attention to this matter.

Sincerely Yours,

Thomas W. Milliner

Encl. (3) Comments, AAE-1, AAE-2
cc: All parties on service list via email

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

IN RE: DEVELOPMENT AND
IMPLEMENTATION OF RULE FOR DOCKET NO. R-30021
INTEGRATED RESOURCE PLANNING
FOR ELECTRIC UTILITIES

Comments Of The Alliance For Affordable Energy on Staff's "Proposed Integrated Resource Planning Rules for Electric Utilities In Louisiana"

Introduction

Now comes the Alliance for Affordable Energy ("AAE"), appearing herein through undersigned counsel, who respectfully submits the following comments on the "Proposed Integrated Resource Planning Rules for Electric Utilities in Louisiana" ("Proposed IRP Rules") prepared by the Staff.

General Comments

As an aid to the Staff and the other parties, in addition to AAE's narrative comments on the Staff's Proposed IRP Rules, AAE also suggests a number of revisions to the Proposed IRP Rules, which are attached hereto as AAE-1. A redlined comparison of AAE's edits with Staff's Proposed IRP Rules is attached hereto as AAE-2.

In AAE-1, we recommend a number of edits to address one or more of the following problems:

- The Proposed Rules frequently repeat instructions and guidance to the utilities, using different language. These situations create the possibility of confusion and contradictions and of future disputes over interpretation of which specific language is controlling. The AAE edit removes many of these redundancies.
- In several places, the Proposed Rules express requirements in terms of what the utilities "should" do, which reads more as a precatory recommendation than a requirement. The AAE edit replaces "should" with "shall."
- In some places, the Proposed Rules require that the utility conduct analyses or provide data that the utility considers pertinent. The rules should lay out the minimum requirements for the IRP; the utility is always free to conduct additional analyses or provide additional information.
- Some parts of the Proposed Rules are unnecessarily vague, including the use of the passive voice (e.g., "this type of analysis is conducted…"). The AAE edit attempts to clarify the requirements, including rephrasing the rules in the active voice, placing the responsibility directly on the utility (e.g., "the utility shall conduct…").
- The Proposed Rules use some terms, such as "load management" in contradictory and confusing ways.

Specific Language Corrections and Clarifications

Definitions Section

Avoided Energy Costs

The Proposed Rules define "Avoided energy costs" to be limited to "fuel and variable O&M." This is an incomplete definition and excludes many other costs which vary directly with the amount of energy generation and consumption, including:

- emissions allowances,
- the retrofitting of environmental controls that vary with energy requirements,
- renewable energy procured to meet renewable portfolio targets, and

- the incremental fixed costs of intermediate or baseload generation resources above the costs that would be incurred simply to meet peak demand or reliability (i.e., the cost of a peaker).

The last point can be quite important. Entergy's 2009 Strategic Resource Plan Refresh estimates that the incremental capital cost of a coal plant in excess of a combustion turbine is about $2,100/kW; at a 10% carrying charge, $20/kW-year of extra O&M for the coal plant, and a capacity factor of 85% for the coal plant, the additional fixed energy-related cost is about $30/MWh. Even existing units can have large avoidable energy-related investment costs. The costs of the retrofits to meet environmental requirements on a coal plant can exceed $1,000/kW, including the following potential costs:

- Flue-gas desulfurization (FGD), also known as a scrubber: $600/kW.
- Selective catalytic reduction (SCR) for NOx control: $200/kW.
- Activated carbon injection for mercury control, plus a baghouse to capture the mercury-laden carbon and other fine particulates: $150/kW.
- Cooling towers: $200/kW.
- Control of ash and scrubber waste: ~$200/kW.

Avoided energy costs will vary by season and time of day, and will typically be higher for load-following load shapes than baseload resources. The avoided energy costs for demand-side resources include the marginal line losses avoided by load reductions, which are roughly twice the average load-related losses in the same period. For example, if the load-related losses at average load are 4%, the marginal losses at that load level would be about 8%. At high loads (50% above average), the load-related losses for the same system would be 6% and the marginal losses would be 12%. Avoided losses attributed to load reductions should include losses on both sides of the meter. For customers served at higher voltages, transformer and distribution losses within the customer facility will tend to raise total losses to be close to those served at secondary.

Avoided Capacity Costs

The proposed Rules define "Avoided capacity costs" as the full cost of whatever new generation unit could be avoided; that definition has several problems:

- Some avoidable resources are life-extensions of existing units.
- A portion of the cost of avoided generation (other than peakers) is properly treated as being energy-related, as explained in the previous section. If not for the need to provide low-cost energy, the utilities would never procure capacity more expensive than peakers.
- Purchases of capacity can be avoidable resources.
- For utilities with excess capacity load reductions will generally avoid some capacity costs. In such situations, load reductions will allow for the sale of additional capacity off-system, early retirement of obsolete or inefficient plants, or mothballing of capacity; the short-term avoided capacity cost is thus the higher of the market price for peaking capacity in the region, or the avoidable operating costs of excess capacity.
- Demand-side programs avoid marginal losses on peak, which are generally much higher than marginal energy losses averaged over the year because losses rise with the square of load.
- Energy-efficiency programs, and in some cases demand-response and load-management programs, avoid reserve requirements. Avoided capacity costs should thus be increased by the required reserve margin.
- Energy-efficiency programs avoid transmission and distribution investments, which are primarily driven by peak load.

Measure

"Measure – An individual project" is not consistent with current usage. A measure is better described as a discrete action or activity. A "project" generally consists of a large number of measures. For example, a lighting upgrade project for an office building may include hundreds of measures, such as replacement of a variety of overhead fixtures and exit signs; addition of daylighting controls, switches, and occupancy sensors; and conversion of elevator downlights to LEDs and sconces to compact fluorescents.

Demand-side Management

The proposed Rules define DSM as "Load control programs, such as air-conditioning load management programs. Note that the term 'demand-side management' is often used in a more general way to refer to all load management programs." The first sentence of this definition is inconsistent with standard usage of demand-side management from the 1970s to the present day. DSM <u>always</u> includes energy efficiency and often includes various load-control and Demand Response programs. In some older references, DSM also includes load-building programs, but this usage is obsolete.

Demand-side Program

Programs are not simply collections of measures. A DSM program is typically designed to reach a specific type of customer (e.g., large commercial) at a specific market situation, such as buildings under design and construction, which can be sited, designed and equipped to minimize energy use; equipment that requires replacement in the near future, for which the customer has a choice of efficiency; and buildings with functional but inefficient equipment than can be retrofitted for higher efficiency. The same measure may be included in multiple programs for multiple classes, sometimes with unique eligibility requirements, savings assumptions or customer incentive levels.

Energy Efficiency

The Proposed Rules define Energy Efficiency as "Conservation programs, such as home insulation measures." This is almost correct, although some conservation measures (such as changes in thermostat settings) may involve a reduction in energy service, rather than just increased efficiency in delivering energy services. But the proposed definition goes on to state that: "Note that the term 'energy efficiency' is also often used in a general way to refer to all load management programs." AAE is not aware of this usage; any description of Energy Efficiency to include load-shifting or load-management programs would be confusing and incorrect.

Screening Tests

The discussion of DSM screening is too long for the definition section. It should be moved to the demand-side subsection of the IRP Development section and revised to comport with current state of practice

Major Issues

I. Stakeholder Involvement and Collaborative Process

AAE commends Staff for its inclusion of a "collaborative process" in the first section of the Proposed Rules. Such collaboratives provide an opportunity to incorporate input from informed ratepayers and stakeholders as well as include independent perspectives from industry experts and other parties. A well-managed stakeholder collaborative can be the venue for compromise and reasoned discussion between parties and an alternative to costly and time consuming litigation. With these objectives in mind, AAE would like to observe that the two collaborative meetings envisioned in Staff's proposed schedule, separated by a ten month period, are likely insufficient for substantial discussion and the identification of compromise solutions addressing very complex and technical material. Based on collaborative experiences in other Southeast jurisdictions, more continuity and more frequent meetings will be required to make significant progress.[1]

In lieu of the two collaborative sessions currently proposed by Staff, AAE suggests that a total of four sessions be implemented, scheduled at intervals of approximately two months. AAE further suggests that regulatory Staff in the nearby states of Mississippi and Arkansas may attest to the productivity of very

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[1] Hale Powell, one of AAE's two expert consultants, has been active in productive IRP and/or energy efficiency collaboratives in Georgia, Mississippi, Virginia and Arkansas. In each of those jurisdictions, collaborative meetings have been held on a much more frequent basis than is envisioned in the Louisiana proposed IRP rules. The current Arkansas energy efficiency collaborative, for example, has been meeting at least on a monthly basis to deal with very detailed material.

recent collaboratives in those states as well as provide the Commission with insights on effectively managing such stakeholder discussions.

II. Energy-Efficiency Program Development

The proposed Rules describe a process of identifying "hundreds of potential demand-side measures," using a screening process to discard a large number of measures, and combining the remainder into programs. This bottom-up process is outmoded and would be inefficient even if it could actually be implemented. In fact, quite the reverse is true. In most mature ratepayer funded energy efficiency efforts it is a top-down program-driven process that is used to develop modern energy-efficiency portfolios.

Instead of starting with hundreds of disconnected demand-side measures and building programs with this outdated bottom-up screening of measures, experienced utilities and other energy-efficiency program administrators start by identifying market segments, designing programs to serve each market segment, and determining the measures and other components of the program. This program-driven approach starts with customer needs, selects the delivery approaches suitable for each market segment, and evaluates measures in the context of the program.

Many programs, such as custom retrofit programs for large commercial customers, process improvements for industrial customers, and new-construction programs, do not normally even have specific lists of eligible measures. The eligibility of all potential improvements in siting, design, equipment and controls is determined by cost-effectiveness screening at the project level.

The same technology measure may be implemented through a variety of programs with different costs and savings. For example, installing high-efficiency fluorescent fixtures instead of standard fixtures might be included in new construction and retrofit programs for residential, small-commercial and large C&I customers. The large-C&I retrofit programs may include both a prescriptive program, with fixed incentives, and a custom program that covers comprehensive retrofits of lighting, window treatments and other measures to reduce internal loads, plus downsizing of the chiller and other improvements in the HVAC system. The delivery and administration costs, incentives and savings will vary among these programs, even for the same technological measure. Starting with a list of isolated measures will not lead to comprehensive programs, and any subsequent screening of measures without the program context will be unrealistic.

The bottom-up approach is rarely used in other planning contexts. Builders and homeowners do not design a house bottom-up by selecting the windows, flooring, furnace, air conditioning, roof tiles, studs, joists, siding, and a hundred other components and then hiring an architect to assemble the pieces into a house. The process normally starts top -down with determining the objectives (customer needs, size, style, number of bedrooms, cost constraints) and then selecting the design and materials.

Pursuant to the Staff's Proposed IRP Rules, if the utilities took the same approach for generation that the proposed Rules prescribe for demand-side resources, they would list all possible fuels, boiler designs, turbines, condensers, cooling towers, feedwater pumps, reheaters and so on, and then design one or more power plants from the selected components. That would obviously be an inefficient way to make supply-planning decisions, especially at the IRP level. Instead, IRP analyses deal with generic plants (e.g., super-critical pulverized coal, 400 MW; 2×1 gas combined cycle, 600 MW), and specific individual components are selected only in the subsequent design process. In the same manner, the IRP should deal with energy-efficiency programs in terms of market segments, general marketing and incentive strategies, and targets for participation and savings.

III. Energy-Efficiency Screening

Screening in the Proposed Rules

Citing the California Standard Practice Manual, Section 6(c)(ii) of the proposed Rules would prescribe the use of four screening tests, defined in Section 2:

- the Participants Test,
- the Rate Impact Measure ("RIM test"),
- the Utility Cost Test, and
- the Total Resource Cost Test ("TRC test").

Section 6(c)(ii) also requires that "Measures that fail the screening test should be eliminated from further consideration in the IRP." It is not clear whether the intent of the proposed rules would require that any measure failing any test would be eliminated, that any measure failing all four tests would be eliminated, or something else.

Obsolete Screening Tests

The Participants Test and the RIM test are relics of the original 1983 California Standard Practice Manual, early in the development of energy-efficiency programs. While they are still described in the Standard Practice Manual, neither test is applied in the form described by the proposed Rules in California or any of the other jurisdictions with major energy-efficiency programs.

The Participants Test

The Participants Test has been discarded by utilities and regulators because it does not answer the question it is intended to answer: whether the proposed program will be attractive to potential participants. Each program should be designed with incentives and program delivery mechanisms that will encourage participation from the targeted market segments. The classical Participant's Test is of little use in helping the utility and the Commission to predict whether the program will work.

Various types of customers respond in different ways to program designs and incentives. A few may perform a discounted payback or lifecycle present-value analysis, as described in the Standard Practice Manual, but most customers probably apply a simple payback requirement, or decide based on such considerations as financing, required approvals, social support, or requirements of participant time and attention. Some commercial, industrial, institutional and government customers cannot contribute more to the initial financing of a project than the first-year operating savings, simply because they cannot raise additional capital funds without approvals that require excessive calendar time and/or staff effort. Some customers may not be able to borrow funds, given their financial condition; or central management may be reluctant to use limited borrowing capability for a discretionary efficiency improvement.

In other situations, the acceptability of the program will not be determined so much by its apparent economics as by the customers' level of trust in the recommendations and representations they receive. A residential program endorsed or cosponsored by a community group, a small-commercial program sponsored by the Chamber of Commerce, and a large-commercial program that works primarily through the architects and contractors the customers routinely rely on for advice, may all provide more participation at a lower cost than an alternative with the same incentive structure but a less-effective design.

Thus, the Participant Test does not represent a reasonable approximation of the acceptability of a program to customers.

The RIM Test

The RIM Test has also been rejected by utilities and regulators serious about promoting energy efficiency because it does a poor job of measuring rate effects (its stated purpose), and a worse job of measuring the fairness or equity of an energy-efficiency portfolio. The RIM test has in the past been an excuse not to pursue energy-efficiency; whenever lost revenues exceed avoided costs, almost all efficiency efforts would fail the RIM.

First, the RIM does not project percentage changes in rates and bills, or any other measure that would be useful to a decision maker concerned about rate levels.

Second, the RIM purports to measure the effect of a utility action on rates. Programs passing the Utility Cost Test and TRC will generally reduce the present value of total revenue requirements, average utility bills, and total costs of energy services, including the costs paid directly by participants. Thus, even if rates rise, energy consumption will fall by a larger percentage, resulting in a net decrease in bills. The Commission and utilities should be striving to reduce the total dollars that customers are paying for their energy services, not necessarily the rate per kilowatt-hour. After all, consumers write checks for bills, not for rates. And reducing bills will leave customers with more income to spend on other needs, while reducing the cost of doing business and increasing the economic competitiveness of the state's industries.

Third, the RIM test does not indicate how the program affects each rate class. Depending on the recovery mechanisms for energy-efficiency costs and lost revenues, and on the allocation of the avoided costs, any overall rate increase may be isolated to the rate classes using the program. If all customers in the class can participate in the programs, everyone's bills may be lower, even if their rates are higher.

Fourth, the RIM does not measure rate and bill effects well because the magnitude of the rate effects of any utility action depend on the timing and magnitude of the program, and cannot be usefully measured on a project-specific or measure-specific basis. Estimates of rate, bill and equity effects are only meaningful on a portfolio basis.

Fifth, the non-participants in one program may be participants in other programs, and non-participants in the first year may be participants in later years. Over time, portfolios of energy-efficiency programs should be designed to offer direct benefits to as many customers as feasible.

More broadly, the equity effect of a DSM program depends on the following factors:

- whether the customer group served by the program is otherwise served more or less than other groups.
- whether the customer group served by the program is more in need of assistance to overcome the barriers to efficiency.
- whether the program is available to a large group of customers.
- whether the magnitude of the program results in a significant rate effect.
- the extent to which the program permanently transforms markets, so that higher-efficiency equipment and designs become standard practice and even non-participants in the program wind up with better equipment and lower bills.

The ratepayer impacts of the energy-efficiency portfolio should be examined carefully to flag any equity problems or disruptive rate impacts. The standard RIM test, however, is not a very meaningful test of equity or rate changes. It looks at rate effects on a measure-by-measure or program-by-program basis, and measures only the average effect on rates, over a long period of time. Individual measures and programs cannot really be considered equitable or inequitable in isolation. Because equity effects should be evaluated for the portfolio as a whole, the standard present-value RIM test is not useful for this purpose. It does not assess the equity effects of energy-efficiency among and within classes, and it does not determine the pattern of rates and bills over time.

It is possible that the energy-efficiency option that most conclusively fails the RIM test would also increase the equity of the portfolio. For example, suppose that a program targeting refrigeration and cooking use of small restaurants has a RIM benefit/cost test of less than 1.0.[2] For that segment of the small-commercial class, this may be the only program in which the customers can participate in a major way. Hence, even if the program increases rates for non-restaurant small-commercial customers, it would help to balance the portfolio by ensuring that all portions of the class have access to significant savings. If a measure or program, or an entire energy-efficiency portfolio, fails the RIM test, that does not imply that rate effects are distributed unfairly, or that rate increases are too large compared to bill reductions. If there are equity problems, they can be addressed by changing cost recovery patterns, by altering the allocation of expenditures among and within rate classes, by increasing the penetration of programs to groups that would otherwise face higher bills, and possibly by changing the timing of particular retrofit programs.

For example, in its 2005 resource plan report, British Columbia Hydro identified seven programs with RIM ratios of 0.6 or 0.7, and determined that they would have miniscule effects on the bills of non-participants, ranging from 0.0002¢/kWh to 0.0089¢/kWh.[3] (Note that these rate impacts are described in "cents", not dollars). Because these rate effects are much smaller than the Commission would normally see, it may be useful to restate them as $0.000002/kWh to $0.000089/kWh, or $0.002/MWh to $0.089/MWh. According to this analysis, even the program with the largest effect on rates would increase rates less than 1/100 of a cent per kilowatt hour. Any non-participants who chose to participate in any of Hydro's efficiency program would almost certainly save more than the miniscule costs that might be shifted to them by low-RIM programs.

The RIM test does not test the equity of a program in any meaningful way. Energy-efficiency efforts should not be rejected simply because it fails the RIM test.

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[2] The RIM test is sometimes computed as a ratio, in which case a ratio less than one would indicate that the program fails the test.

[3] BC Hydro 2005 Resource Expenditure and Acquisition Plan, Table 4-7.

Avoiding adverse effects on groups of customers is certainly an important consideration for utilities and the Commission. Those effects can be better assessed by analyses such as those performed by BC Hydro, or more detailed analyses of rates that would be charged to specific customer groups, rather than the uninformative RIM test.

Finally, a serious defect of the RIM test is that it disproportionately focuses on the small near term rate impacts of energy efficiency programs while entirely ignoring the much larger rate impacts associated with future large capital investments in new generation assets. It is clear that that effective energy efficiency programs can minimize or defer the necessity for such large capital investments. As such, any near term small rate impacts associated with energy efficiency programs can be an effective tool for minimizing ratepayer (and overall macroeconomic) exposure to much larger double digit rate increases associated with multi-billion dollar capital construction projects.

IV. Risk Treatment

The proposed Rules include some requirement for examining the effects of changing input values on the costs of various resource plans (in the form sensitivity and scenario analyses), but they appear to assume that the resource plan would remain fixed in the face of changing conditions. One important difference among resources is the varying extent to which they permit utilities the flexibility to change direction in response to changing circumstances. Energy-efficiency and load-management programs produce savings essentially as soon as investments are made, and can be cut back at any time without losing the benefits of completed projects. A major power plant, on the other hand, can easily take six years or more of permitting and construction and run the risk of being cancelled after substantial amounts are expended on construction. For example, Entergy's proposed repowering of the Little Gypsy plant was cancelled after four years and at a cost to ratepayers of roughly $200 million. Many nuclear plants completed in the 1980s and 1990s experienced substantial cost overruns and took over a decade from the start of actual construction. Entergy has already spent several years and over $70 million investigating the feasibility of constructing a new nuclear plant that will not be completed for at least 10 to 15 more years, if ever.

Hence, the AAE revision of the Staff Proposed IRP Rules retains the sensitivity and scenario analyses, while adding a flexibility analysis, in which the utility would examine the extent to which the resource plan would allow the utility to adapt to changing circumstances.

V. Historical Data

Historical forecasts should be provided and reviewed for at least five years, to cover the typical business cycle and allow the PSC to better evaluate the utility's forecast methodology. The Proposed IRP Rules require only the examination of forecasts prepared between IRPs, which might be only two annual forecasts; even the previous IRP forecast would not be reviewed.

VI. Resource Screening

The automatic resource selection programs described in the proposed Rules may be useful, but they are not necessary. Utilities, especially the smaller ones, may have few resource options and decisions, and may be able to analyze the choices without the cost of an optimization model. In any case, a utility that uses an optimization model would need to be able to explain to stakeholders and the Commission why the selected result is correct. The explanation of "The computer did it" is no longer acceptable. Hence, the AAE revision of the Staff proposal describes plan selection more broadly, allowing but not assuming the use of optimization models.

VII. Estimations of Efficiency Potential

In order to ensure the appropriate balance between supply and demand side resources it is essential that IRPs incorporate a credible estimate of the magnitude of available cost effective energy efficiency resources. An under-estimate of efficiency resources will result in ratepayer over-expenditures for costly new plant and equipment whereas an overestimate could result in an under-investment in new capital stock. Both scenarios entail substantial risks to ratepayers.

In order to mitigate such risks AAE recommends that a periodic "DSM potential study" be required as the basis for IRP estimates of available energy efficiency resources and that such studies should be updated, at the minimum, every four years.

Efficiency potential studies are commonly conducted in many jurisdictions for purposes of informing long term resource plans and assisting in developing effective DSM programs. AAE can provide the Commission with a variety of such studies in other jurisdictions if so requested.

It is important to keep in mind the results from such potential studies are not necessarily "scientific" and are potentially biased if conducted by a single party without benefit of transparency and substantial review by independent experts or other stakeholders. An example of this potential issue is the very low estimates of energy efficiency potential produced by Entergy's 2009 system-wide DSM Potential Study. The results of this study, utilizing a variety of technical assumptions that were unreviewed by other parties, were submitted in efficiency and IRP dockets in Arkansas and New Orleans[4].

Anticipating such problems, AAE encourages the Commission to require that DSM potential studies be conducted in a transparent manner and that experts and stakeholders have an opportunity to substantially review all assumptions that underlie final estimates of energy efficiency potential.

VIII. Additional Reporting Requirements

Many of the requirements in the Additional Reporting Requirements section were related to data or analyses required in other sections. In those cases, we moved the reporting requirement up into the sections describing the data and analysis requirements. Thus, while this section is much shorter in the AAE revision, all the requirements in the Staff draft are included in appropriate context.

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[4] In 2010, after considerable input from experts and interveners, and the completion of an independent potential study, the Arkansas PSC concluded that much higher potential energy savings were achievable than the levels identified by Entergy and that energy savings targets would be based on these higher estimates.

IRP Schedule

For clarity, AAE proposes to move the discussion of stakeholder comments and the inclusion of those comments in the IRP Report, from the schedule section to a separate section.

The IRP Schedule section of the Proposed Rules has four major problems.

First, the Proposed Rules do not actually identify start dates for the IRP cycles for the various utilities. The AAE edit proposes specific dates for the beginning of each utility's IRP cycle.

Second, the Proposed Rules would provide for an IRP filing at the soonest every 38 months, with longer intervals if a hearing is required. This period appears to result from a 15-month dead period between the end of one cycle and the beginning of the next. This cycle is simply too long and should be reduced to reflect the high degree of uncertainty and volatility in current energy markets and regulatory requirements. Four years ago, in late 2007:

- The economy was booming;
- gas prices were over $9/MMBtu, with forward prices for 2020 at the same level;
- the wind-turbine market was very tight with prices high;
- the Clean Air Interstate Rule had recently been vacated, and it was unclear what new NOx and SO_2 rules would be propose and when; and
- the EPA had yet to release its proposals for regulating hazardous air pollutants, cooling water use, or coal-plant wastes, and the NAAQS requirements appeared to be relatively stable.

Today, the situation is radically different:

- the economy has not recovered from the worst recession in six decades;
- gas prices are under $4.50/MMBtu and forwards for 2020 are under $7/MMBtu;
- the global slow-down and increased manufacturing capacity have created excess wind-turbine supply and steeply reduced prices;

- the Clean Air Interstate Rule has been replaced by the proposed Clean Air Transport Rule and now the Cross-State Air Pollution Rule, with more limited trading;

- EPA has released proposed rules for Hazardous Air Pollutants, cooling water systems, and coal-plant wastes, and started the process for setting emission limits for greenhouse gases and power-plant effluent, while the NAAQS for have been tightened for ozone and SO_2 (including a new one-hour standard) and new particulate standards are due in late 2011; and

- A number of studies have found that a large number of power plants, especially coal-fired units, are likely to retire to avoid the new environmental requirements.

In short, conditions change quickly enough to warrant much more frequent filings. Using the Proposed Rules' 18-month schedule for the first IRP cycle, and adding six months if hearings are required, biennial filings appear to be feasible. The three-year cycle in the Proposed Rules is at the high end of fixed IRP cycles; several states (Arizona, California, Delaware, Idaho, Iowa, Minnesota, New Hampshire, South Dakota, Utah, Virginia, Washington) require biennial filings and some (Connecticut, Florida, Montana, Ohio, South Carolina) require annual filings or updates. The AAE proposed schedule uses the same 18-month schedule for all cycles, leaving six months following each cycle for hearings and a Commission order, if necessary.

Third, the Proposed Rules do not provide for any discovery by stakeholders or Staff, which limits their review of the IRP to whatever information the utility chooses to provide. For example, the stakeholders might need information from the utility regarding the distribution of customer business types, end-uses and efficiency levels; long-term purchase options offered by third parties; customer inquiries regarding interconnection of cogeneration and renewable facilities; the condition and maintenance requirements for existing facilities; and plans for environmental compliance. AAE's revision adds opportunities for written data requests following the Draft and Final IRPs.

Fourth, the proposed Rules provide very little time for stakeholders to prepare comments following the two scheduled Stakeholder Meetings, and provide no opportunity for comments on the Final IRP. AAE's revision adds time to the schedule to allow for thoughtful comments.

Conclusion

According to a recent report by the Regulatory Assistance Project, at least 36 of the 50 states have Integrated Resource Planning or similar planning processes. (Farnsworth, D., "Preparing for EPA Regulations: Working to Ensure Reliable and Affordable Environmental Compliance," July 2011). Of the 14 states without such requirements, six are states whose utilities have divested their generation and one is Texas, whose major utilities have divested. Thus, Louisiana is one of only seven states with primarily regulated generation and no systematic IRP process.

The present docket will help bring Louisiana into the mainstream for utility planning which will be a boom not only for the state's ratepayers, but also be an aid to the economic development of Louisiana. The Alliance for Affordable Energy welcomes the opportunity to comment on the Staff's Proposed IRP Rules and looks forward to working with the Staff and the other stakeholders to develop a set of IRP rules for Louisiana that draws upon the lessons learned and the best practices of other jurisdictions.

Respectfully submitted,

Anzelmo, Milliner & Burke, L.L.C.

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Counsel for the Alliance for Affordable Energy

Certificate of Service

I hereby certify that I have on this 28th day of September, 2011, served copies of the foregoing pleading upon the all known parties to this proceeding by U.S. Mail, email, facsimile and/or hand delivery.

Thomas W. Milliner

AAE-1

Proposed Integrated Resource Planning Rules For Electric Utilities in Louisiana

1) Overview

The following Integrated Resource Planning ("IRP") Rules shall be used by jurisdictional investor owned and cooperative electric utilities regulated by the Louisiana Public Service Commission ("Commission" or "LPSC") to develop long-term Integrated Resource Plans ("IRP"), which include both supply and demand-side resources, and considers transmission impacts, in order to satisfy the utility's load requirements. An electric utility's IRP shall be relied on by the utility as it creates its internal business plans. These rules are intended to provide utilities the flexibility to develop plans that meet their own specific needs and circumstances, to encourage a collaborative working process with all stakeholders, and to be consistent with the requirements of the Commission's Market Based Mechanism Order ("MBM")[1] and the 1983 General Order.[2]

Resource planning under these rules does not change the fundamental relationship between the utilities and the Commission. The Rules do not mandate a specific outcome nor do they mandate any specific investment decisions to be made. Resource planning should reflect each utility's unique circumstances and the judgment of its management, and each utility will continue to bear the full responsibility for the consequences of its decisions. Resource planning decisions made as part of the utility's IRP process will be relevant to future investment decisions and approval proceedings, as well as revenue requirement and rate design proceedings. Consistency of a utility's Integrated Resource Plan with these Rules will be an additional factor for the Commission to consider in evaluating the prudence of investments in construction and rate application proceedings. Any changed circumstances that occur after the IRP has been developed should also be considered in those proceedings.

2) Definitions

a) Allowance – In conjunction with environmental legislation, an allowance provides an entity the right to emit a certain amount of emissions. With regard to SO2 provisions in the Clean Air Act Amendments of 1990 (PL 101-

[1] General Order, Docket No. R-26172 Subdocket A, *In re: Development of Market Based Mechanisms to Evaluate Proposals to Construct or Acquire Generating Capacity to Meeting Native Load, Supplements the September 20, 1983 General Order,* dated February 16, 2004 (as amended by General Order, Docket No. R-26172 Subdocket B, dated November 3, 2006, by the April 26, 2007 General Order, as referred to as the "MBM General Order", and further amended by the General Order, Docket No. R-26172 Subdocket C, dated October 29, 2008)

[2] General Order, *In re: In the Matter of the Expansion of Utility Power Plant; Proposed Certification of New Plant by the LPSC*, dated September 20, 1983, as amended by the General Order in Docket No. R-30517 dated October 29, 2008, and corrected May 27, 2009.

549) at Title IV (known as the Acid Rain Program), one allowance give a utility the right to emit one ton of SO2. Allowances may also be considered in conjunction with other pollutants such as NOx, C02 and similar greenhouse gas emissions, and mercury.

b) Avoided Cost –

i) Avoided energy costs are the fuel, variable O&M expenses and other costs (including commitments to fixed costs) a utility avoids by, for example, purchasing energy from another party or reducing energy consumption through energy-efficiency programs. Avoided energy costs will vary by season and time of day, and will typically be higher for load-following load shapes than baseload resources.

ii) Avoided generation capacity costs reflect the value to the utility and its customers of reducing peak loads and the need for capacity peaking-equivalent of the portion of the cost of new generation resources, or the market value of freeing up existing that could be avoided, for example, by reducing peak demand as a result of a demand-side management program. Avoided generation capacity costs for energy efficiency include the reserve margin avoided by load reductions.

iii) Avoided transmission and distribution costs reflect the expected value of investments avoidable or deferrable by load reductions, generally estimated from the long-term ratio of historical or projected investments to load growth in the same period.

iv) All avoided costs must include avoided losses from the end use back to the level at which the avoided cost is estimated (e.g., energy at generation).Cogeneration - Production of electricity by a Qualifying Facility, which the utility is required to purchase, as defined in the Public Utility Regulatory Policies Act ("PURPA") of 1978, at 16 U.S.C. Section 796. Additional policies concerning PURPA requirements were addressed in the Energy Policy Act of 2005, Title XII, Subtitle E, Section 1253, and in the Energy Independence and Security act of 2007, Section 515.

c) Commission – The Louisiana Public Service Commission.

d) Collaborative Working Process - A process, authorized by the Commission, in which utility and non-utility stakeholders have an opportunity to provide detailed input into the development, and final recommendations, of the Integrated Resource Plans developed under these rules. Such a process is intended to provide an informal, but substantial, venue in which a reasonable balance between private and public interests can be identified and incorporated, if possible, within the final IRP plans.

e) Demand Response – Load-management programs that have the intended goal of reducing load during the actual hours with high energy costs and/or supply problems.

f) Demand-side:

   i) Energy-efficiency measure - any device, technology, or operating procedure that makes it possible to deliver an equivalent level and quality of end-use energy service while using less energy or peak demand than would otherwise be required.

   ii) Management - Energy efficiency and load-management programs.

   iii) Market Segment - A portion of the potential DSM market, with common characteristics which may require a unique approach to DSM program design or implementation. Market Segments are generally differentiated by customer class (residential, small C&I, large C&I), other customer distinctions relevant to delivery methods (e.g., low income, multi-family, rental, non-profit, government, food-service) and market opportunity (new construction and renovation, routine equipment replacement, early replacement, and retrofit).

   iv) Portfolio - The totality of the utility's efforts to promote end-use energy efficiency.

   v) Potential studies - Studies conducted to assess energy savings potentials for different technologies and customer markets. Potential is typically defined in terms of technical potential, market potential, and economic potential.

   vi) Program – A coordinated set of tools - including marketing, outreach, training, delivery, incentives, verification and evaluation - addressing the needs of a particular market segment, designed to reduce a utility's capacity and/or energy requirements.

g) Energy Efficiency - The provision of the same energy services (light, warmth, cooling, industrial output, etc.) while using less energy such as home insulation measures.

h) Externalities - Environmental and social costs or benefits that result from the production or delivery of energy, and are not reflected in the prices paid by the utility and its customers.

i) Integrated Resource Planning - A type of utility planning process that develops long-range resource plans, seeking the optimal combination of resources (including demand and supply-side options) that meets forecast requirements at the lowest total cost, subject to reliability, planning, environmental and operational constraints and the value of risk reduction.

j) IRP Report - The document describing the resources that the utility plans, in order to meet its forecasted load requirements both reliably and economically. The report should fully describe input data assumptions used, modeling methodologies relied on, evaluations performed, results produced, and conclusions reached, with regard to the selection of the utility's long-term resource plan.

k) Load Management - Measures and programs that curtail or shift loads from high-cost or high-demand periods. Load-management programs include direct load control (such as of air conditioners and water heaters), demand response involving two-way communications reflecting actual conditions, and interruptible rates.

l) Lost-opportunity efficiency resource - An energy-savings opportunity tied to a transient market opportunity, such as designing and building a new building; major renovations and expansions of buildings and production lines; replacing failed, failing and obsolete equipment; and purchasing new equipment.

m) Planning Period – The period for which the plan projects resource requirements. The default planning period for the IRP is 20 years, but the utility may use a shorter period, if it can provide justification supporting the use of that period and demonstrate that end effects have been adequately reflected. Such justification should be included in the utility's IRP Report. In addition, a five-year Action Plan should be created and included as part of the IRP Report. The Action Plan should describe the specific actions that the utility expects to take during the first five years of the planning period in order to fulfill the requirements of the IRP.

n) Probable environmental cost: means the expected cost to the utility of complying with new or additional environmental legal mandates, taxes, or other requirements that, in the judgment of the utility decision-makers, may be imposed at some point within the planning horizon which would result in compliance costs that could have a significant impact on utility rates

o) Program Evaluation: The performance of studies and activities aimed at determining the effects of a demand side program; any of a wide range of assessment activities associated with understanding or documenting program performance, assessing program or program-related markets and market operations; any of a wide range of evaluative efforts including assessing program-induced changes in energy efficiency markets, levels of demand or energy savings, and program cost effectiveness.

p) Power Purchase – A transaction to purchase capacity and or energy from another electric power supplier that will partially satisfy the utility's load requirements. Power purchases can encompass different time periods, as follows:

   i) Short term – A purchase of one year or less, which is not required to be procured pursuant to a RFP, as set forth in the Commission's MBM Order.

   ii) Long Term – A purchase that lasts more than one year, which must satisfy the Commission's MBM Order requirements.

q) Retrofit efficiency resource - An opportunity to increase the efficiency of a building, equipment, process, or other end use by adding to or replacing existing plant or equipment, or changing procedures. By their nature, retrofits can be implemented earlier or later, to minimize total costs and promote efficient implementation.

r) Stakeholders - Individuals or other entities which have a reasonable likelihood of being significantly affected by the electric resource investments considered within the IRP process. Among other parties, this includes representatives from regulatory agencies, utilities, customers of such utilities, and consumer and environmental advocacy groups that are duly constituted and organized as such.

s) Supply Resource - An electric generating unit, either owned and/or operated by the utility or a portion of such unit; or a purchase of capacity and/or energy from one or more such units or from the seller's system supply. Supply Resources may include upgrades or life extension for existing units or plants.[3]

t) Utility - any electric utility furnishing service within the State of Louisiana and subject to the jurisdiction of the Commission.

3) Overview of the IRP Process

a) The overall objective is to develop a base case IRP based on the most economic and reliable combination of resources, including supply, demand-side and transmission resource options, in order to satisfy the forecasted

[3] It may also be appropriate to treat as separate resource options some major transmission projects that could provide access to economic generation resources either from outside the utility's service territory or between zones within the service territory.

energy-service requirements.[4] All constraints such as reliability and environmental requirements must be accounted for in the planning process. The planning process shall include, at all stages, a reasonable level of participation by a collaborative process as authorized by the Commission.

b) A forecast of peak load and energy requirements shall be developed as the first step of the IRP process. The load forecast shall be developed covering the IRP planning period, and shall identify the effects of non-utility energy activities that may affect the level of future energy consumption or peak demand. These would include, for example, lighting- and appliance-efficiency standards and improved building energy codes.

c) The Plan shall assess the condition of all existing supply and load-management resources, including existing purchase and sale transactions. Any committed additions and retirements—those that are fixed by contract or regulatory requirement—should be identified, along with any anticipated reratings. For each existing generation resource, the utility shall provide estimates of the costs of keeping the resource in service, including fixed O&M, routine capital additions, and environmental compliance. Where the utility cannot reliably estimate the costs of compliance with existing or pending environmental regulations, the IRP should include a description of those regulations and the range of potential requirements and costs.

d) The utility shall determine the resource capacity required to serve its forecast loads. That determination may be based on the rules and requirements of the relevant planning authority or on a system reliability assessment, reflecting the utility's loads, resources, and interconnections. The end result of the reliability assessment is the determination of target reserve margins to be used in the IRP process.[5]

e) The utility shall estimate future resource needs, as the product of the planning reserve margin target times forecast peak load, minus the existing supply and load-management resources adjusted for any committed additions and retirements (both supply and demand-side). Any positive difference reflects a need for peak-demand resources over the planning period.

f) The utility shall identify all resource alternatives that may potentially be cost-effective in meeting the utility's peak resource needs or reducing total costs or risks over the planning period. Resources to be considered would include conventional central thermal generation, renewable generation, and cogeneration; distributed generation; utility-owned and non-utility resources; energy-efficiency programs; load-management options; and transmission

[4] Most new central generation resources will require transmission interconnection and integration costs, which should be treated as part of the cost of the resource.

[5] The Plan should be clear as to the nature of the peak load from which the reserve margin is computed (e.g., normal or extreme weather; the utility, holding-company or regional peak).

upgrades that provide access to potentially economic supply-side resources. The remainder of the IRP process consists of the data, tools, and methodologies needed to evaluate these resource alternatives in an appropriate manner.

g) The plan shall describe the development of the energy-efficiency portfolio, which shall include all cost-effective and feasible lost-opportunity resources plus the majority of feasible cost-effective retrofit resources over the Planning Period.

h) The plan shall describe the utility's analysis of distributed-generation program options, including the potential for distributed generation to reduce line losses and avoid T&D investments, as well as the utility's programs for encouraging development of distributed generation in the most beneficial areas and for facilitating the installation of customer-owned distributed generation.

i) The plan shall include a comprehensive description of the utility's programs and policies to reduce losses in the T&D system, including:

   i) Policies and guidelines for selecting new conductors and transformers to minimize total costs, including energy and capacity losses at marginal costs.
   ii) Programs for determining where loss reductions justify reconductoring or upgrading feeder voltage; replacing transformers before failure; and adding capacitors.

j) If the utility identifies many potential supply alternatives, it shall select a manageable number of the most promising options. A screening process is particularly helpful when there are several similar choices of generation technologies available (e.g., sub-critical, super-critical, fluidized bed, and IGCC coal) All resource options that have not been excluded by the screening process should be considered further in the utility's IRP process.

k) The utility shall construct a reference expansion plan that meets all constraints (e.g. reliability, environmental, etc.), and has the lowest net present value revenue requirement, considering all relevant costs (fuel, O&M, capital and environmental). The reference plan shall include all cost-effective lost-opportunity and loss-reduction resources, plus retrofit resources at the maximum efficient pace and additional distributed and central-station generation as necessary to meet requirements.

l) The next step is to conduct risk analyses. The purpose of these analyses is to determine whether a change in the resource plan will reduce vulnerability to higher bills or higher revenue requirements as a result of reasonably foreseeable changes in inputs.

m) The utility shall select the final preferred expansion plan portfolio, reflecting expected total cost to customers, risk, uncertainties, environmental and other considerations.

n) The final step of the IRP process is to develop an Action Plan that details the specific activities the utility expects to take to implement the IRP during the first five years of the planning horizon.

The following sections provide more detailed requirements regarding the development of the IRP, including reporting requirements that must be documented in the IRP Report.

4) Energy and Peak Demand Forecast

This section describes in additional detail the load forecast requirements, and explains the information that must be included in the IRP Report concerning both the utility's actual historical load and its forecasted load. The utility shall define the type of peak load reported (e.g., operating company peak, contribution to holding-company peak, contribution to pool or other area peak), and clearly differentiate among retail and wholesale loads.

a) Time Frame

i) Historical energy requirements and peak demand should be reported covering at least the ten years prior to the first year of the IRP planning period and for at least the time period used in constructing the forecast.[6]

ii) Forecast period. Energy and peak demand should be forecast for each year of the IRP planning period.

b) Energy and Demand Information Supplied in the IRP Report

i) Historic load data shall include the following, in both actual and weather-normalized terms (including the methodologies and processes used to normalize for weather):

(1) The total annual energy consumption for electricity for the utility and for each of the utility's customer classes;

(2) The summer, winter and annual coincident peak demands for the utility and for each of the customer classes, to the extent the utility has developed such estimates by customer class;

(3) Monthly energy consumption for the utility and for each of the customer classes;

[6] For example, if the forecast is based on twenty years of historical data, the Plan should provide those data.

(4) Annual load factor for the utility and for each of the customer classes, if available by customer class.

(5) To the extent any historical data differ from previous filings (e.g., FERC Form 1, p. 402), the utility shall explain the differences.

ii) Previous Forecast Evaluation. Each IRP Report shall contain an evaluation of peak demand and energy forecasts produced by the utility in the five years prior to the filing of the IRP, including the following:

(1) An assessment of the accuracy of the previous forecasts;

(2) An explanation of the cause of any significant deviation that occurred between the prior forecast and the actual peak demand and energy;

(3) An explanation of revisions to subsequent load forecast methodologies and assumptions utilized to correct for prior deviations in the prior load forecast.

(4) An explanation of the impact that demand-side programs, interruptible load or modified energy codes or standards had on the prior load forecast.

iii) Forecast Load Data: The IRP Report shall include the following information:

(1) The total annual weather-normalized energy consumption of electricity for the utility and for each of the utility's customer classes;

(2) The summer, winter and annual coincident peak demands for the utility and for each of the customer classes, if available by customer class;

(3) Monthly energy consumption for the utility and for each of the customer classes;

(4) Annual load factor for the utility and for each of the customer classes, if available by customer class.

iv) Forecast Documentation. Each IRP Report shall contain an evaluation of the projected peak demand and energy forecast, including the following:

(1) Description and full documentation of the econometric or end-use forecasting models utilized, including a demonstration that the approach is consistent with or superior to typical utility industry load forecasting practice.

(2) The historical data used to estimate, calibrate or validate the model.

(3) Projections of all variables driving the power forecast (e.g., measures of economic activity, customer number, power prices, efficiency standards) and the sources of those projections.

(4) A quantification of the impact that demand-side programs, energy codes and standards and interruptible loads had on the load forecast.

(5) Documentation of the amount of losses included in the forecast, including the extent to which the forecast includes the effects of current and planned loss-reduction programs.

5) Existing Resource Evaluation

This section describes in additional detail the existing resource evaluation, and discusses information that must be included in the IRP Report.

a) Existing Resources. The utility should evaluate and discuss in its IRP Report capacity and energy available and expected from each existing resource, including

i) Utility-owned generation,

ii) Power purchases from any supplier,

iii) Unit-specific sales and any other sales not reflected in the load forecast,

iv) Exchange energy,

v) Pooling or coordination agreements that reduce resource requirements,

vi) Load management programs and interruptible contracts, and

vii) Any other supply or demand-side resources.

The utility shall also describe any important changes to the resources that occurred since the last IRP Report was filed. Any program evaluation research or reports which quantify the savings of utility demand side programs shall also be provided and briefly summarized.

b) Existing Generation Resources. The following data should also be supplied for each utility-owned or unit-specific resource:

i) Resource type

ii) Capacity

iii) Fuel type, efficiency and costs

iv) Fixed and variable O&M

v) Ownership information

vi) Location

vii) Commercial operation date

viii) Condition of the resource, and for any resources expected to retire (or any purchases expected to end) within the next ten years, expected retirement date and an explanation of the basis for the expected retirement

c) Existing Demand-Side Resources. The following data shall also be supplied for each existing energy-efficiency and load-management program:

i) Program name and description

ii) Market segment addressed, including customer class(es) included; end uses, business type, or building type targeted; whether addressing new construction, routine replacement, or retrofit market.

iii) Start date and anticipated program life remaining

iv) Historical results, including level of customer participation; level of measure penetration; and estimated capacity, energy and cost savings achieved

v) Any program evaluation research or reports which quantify the savings of utility demand side programs shall also be provided and briefly summarized.

vi) Levelized costs of energy savings achieved

vii) Identification of avoided costs used in demand side cost effectiveness analysis, the date and methodologies used in developing these avoided costs

viii) Nature of program process and impact evaluation, including evaluation schedule and citations to all completed and pending evaluation reports.

d) Existing Transmission System. The following transmission system data shall be supplied:

i) A list of existing and approved transmission lines, identifying for each origin, terminus, operating and design voltage, length, number of circuits, size and material of conductor, and maximum capacity (MVA).

ii) A list of existing and approved substations, identifying for each location, voltages, and the number and capacity of transformers for each voltage combination.

iii) The topology of the transmission system, in maps, diagrams and/or other formats.

6) Development of the Integrated Resource Plan

This section describes in additional detail the development of each utility's IRP, and discusses information that must be included in each utility's IRP Report.

a) System Reliability Assessment. The utility shall determine the resource capacity required to serve its forecast loads. That determination may be based on the rules and requirements of the relevant planning authority or on a system reliability assessment, reflecting the utility's loads, resources, and interconnections. The system reliability assessment would estimate the reliability of the system with existing and committed resources and projected load, and determine the amount of generic capacity (if any) that must be added to maintain the reliability criterion. If the utility conducts a system reliability assessment, it shall specify the reliability criterion selected, which may be one-day-in-ten-year loss-of-load probability ("LOLP"), or a similar loss-of-load or unserved energy expectation criterion. The utility shall explain how the verbal criterion was implemented as a numerical target (for example, whether one day in ten years is interpreted as 24 hours of shortage per 87,600 hours, or one hour of shortage per 87,600 hours). The IRP Report shall document the final reserve margin target used and provide complete details regarding how the target was derived, including a description of any analysis that was performed, the data and assumptions that were used, and the results of the reliability assessment.

b) Resource Needs Assessment – A resource needs assessment should be performed considering the planning reserve margin target, the load forecast, the existing supply and load-management resources, and any committed additions and retirements (both supply and demand-side). The result of the resource needs assessment will indicate the utility's capacity needs for peak demand over the planning period. The utility's resource needs assessment should be fully described in the IRP Report.

c) Demand-Side Resource Analysis

i) The utility shall provide and summarize the estimates of any Louisiana specific energy efficiency (DSM) potential studies which have been conducted subsequent to the last IRP filing. The utility shall also demonstrate how the results of such studies have been incorporated within its proposed portfolio of energy efficiency programs. If no such potential studies have been conducted or updated within the prior four years it shall be the responsibility of the utility to conduct such a study or update and ensure that stakeholders have an opportunity to provide input into the development and findings of such research.

ii) The utility shall identify a range of cost effective and comprehensive demand-side programs that collectively will address all market segments and allow all customers to participate in energy-efficiency programs. Such programs shall be designed and implemented in conformance with national "best practices" for such programs.

iii) Separate programs shall be identified to address new-construction, routine-purchase and retrofit opportunities for all significant customer and market sector groups.

iv) Separate programs shall be identified for each distinct customer group or market segment with significant levels of cost effective savings potential Those groups will vary by utility, but are likely to include residential, small commercial, large commercial and industrial, and outdoor lighting. It may also be appropriate to include separate programs for farms (due to their distinct end uses), low-income customers and/or renters (due to the special challenges of reaching these customers), mobile homes (due to their specific technologies), governmental and institutional customers (due to their specific financing and approval issues), large industrial customers (due to the complexity of improving process efficiency), specific industries or business types, or other groups.

v) For each program, the IRP Report shall include the following information:

(1) The class(es) and market segment targeted by the program.

(2) A description of the range of measures and projects that are or would be covered by each program.

(3) Actual and proposed incentive structures, and an explanation of why the utility believes that the incentives would promote appropriate levels of participation.

(4) Projections of market participation potential for the program.

(5) Projections of program costs and the basis for those projections.

(6) Projections of peak load (kW) and annual energy (kWh) effect, reflecting the percentage of measures that would have implemented without the program, and the extent to which non-participants implement additional measures due to the program;

(7) Estimates of the effective useful lives ("EUL") of the measures that would be installed under the program. Such estimates, in general, should reflect the lifetime assumptions that have been validated, and are in wide use, in jurisdictions with comprehensive efficiency programs. Utilities shall identify the origin of all EUL values utilized.

(8) Estimates of participant benefits, if any, other than electricity savings (e.g., gas savings, water savings, reduced operating and maintenance costs, deferring future equipment replacements).

vi) The IRP shall include demand-side screening using the following methods.

(1) The principal screening test for measures and programs is the Total Resource Cost ("TRC") test, which measures the net benefit of a demand-side management program as the difference between the total costs and benefits of the program, including both the participants' and the utility's costs. The *benefits* calculated in the TRC test are the avoided supply costs, including all the cost reductions identified in Section 2)b), plus any non-electrical benefits to participants. The *costs* in this test are the program costs paid by the utility and the participants plus any increases in supply costs (e.g., due to increased off-peak usage) and participant costs, net of any tax credits. Thus all equipment costs, installation, operation and maintenance, cost of removal (less salvage value), and administration costs, no matter who pays for them, are included in this test. The TRC determines whether the program or measure is cost-effective.

(2) The secondary DSM screening test is the Utility Cost Test, which measures the net effect on costs that flow through the utility. The benefits are the avoided supply costs. The costs are those incurred by the utility, including the incentives paid to participants, any increase in supply costs, initial and continuing program implementation and administrative costs. For load-management programs, costs may also include utility control and communication equipment and installation, operation and maintenance, and costs due to customer dropout and removal of equipment (less salvage value). The Utility Cost Test determines whether the costs to the utility system exceed the benefits to the system.

(3) The utility should endeavor to procure all efficiency savings that pass the TRC test (benefits minus costs are greater than zero).

(a) If a proposed program passes the TRC test but fails the Utility Cost Test, the utility shall review the incentives in the program and attempt to raise the Utility Cost Test to a positive number. The IRP Report should discuss any conflicts between the TRC and Utility Cost Test.

(b) If a proposed program fails the TRC, the utility should determine the reason for such failure, and improve the program by removing non-cost-effective measures, adding measures or improving incentives to increase benefits and cover fixed costs, or otherwise redesign the program to provide cost-effective efficiency services to the targeted market segment. If the utility cannot design a cost-effective program for the market segment, the IRP Report should explain the nature of the problem and the utility's attempts to correct it.

(c) If the utility proposes to pursue a program that does not pass the TRC (e.g., for low-income customers), the IRP Report should explain why the program is not cost-effective and why the utility has chosen to pursue the program.

(4) Programs shall be screened including all benefits and the incremental costs of adding the program to the portfolio. For programs that would offer a discrete set of measures (as opposed to custom implementation), measures should be screened including all benefits and the incremental costs of adding the measure to the program.

vii) The IRP projection of energy-efficiency programs shall include developments beyond current conditions, reflecting continuing improvement in end-use technology and program design, offset by the rise in standard practice and efficiency standards reflected in the utility's load forecast.

viii) The IRP Report shall include a comparison of the projected energy-efficiency results to goals and achievements of leading utilities and other program administrators, considering the utility's current and future experience with energy-efficiency programs. If the IRP Report does not project results comparable to those of the utilities and program administrators with the largest savings, the Report shall explain why.

d) Supply-side Options

i) A range of supply-side resources (both generation technologies and capacity purchases) shall be evaluated. The utility shall compile a list of resources that are likely to be feasible, including both renewable and non-renewable options, and both utility ownership and purchase from IPPs and merchant plants. For each supply-side option on this list, the utility should include in its IRP Report a description of the option, including at least the following information:

(1) Resource type, including

(a) whether the resource is specific (a purchase from an existing resource, construction of a particular unit at a particular location, life-extension or repowering of a particular unit) or generic
(b) unit type (e.g., boiler, combustion turbine, combined-cycle; sub-critical, super-critical, fluidized bed, IGCC) and ;

(2) Unit and plant capacity, nominal and summer firm;

(3) Fuel type and heat rate, if applicable;

(4) Potential or actual ownership information (e.g., wholly owned by the utility, jointly owned, third party ownership);

(5) Location and effect on transmission adequacy;

(6) Anticipated life;

(7) Availability;

(8) Operating costs, including O&M, property taxes and capital additions;

(9) Operational characteristics, including dispatchability, ramp rates, start-up time, minimum load level, minimum up time, and minimum down time.

(10) Capital cost and AFUDC estimates, if applicable;

(11) Probable environmental costs associated with continuing operation during the planning period.

(12) Any other information deemed pertinent by the utility.

ii) Supply-Side Screening. If a large number of potential supply alternatives are identified, the utility shall select a manageable number of the most promising options. One approach for screening supply-side options is to compare the levelized revenue requirements over the life of the resource at varying capacity factors. Some resources may be dominated by alternatives at all capacity factors and thus be unlikely to be preferred resources. However, considerations other than levelized cost per MWh may be important in supply planning, including dispatchability, load-following, and other measures of operational flexibility. The supply-side screening process shall be fully described in the IRP Report. If the utility eliminates any supply-side resources based on its screening analysis, each such resource shall be described in the IRP Report and the reason for elimination shall be explained.

e) A ten year transmission plan shall be provided containing details of all approved and proposed projects at or above the 115 kV level.

i) For each approved or planned new, upgraded or rebuilt transmission facility, the Report shall include at least the following information:

(1) The nature of the project (e.g., line, substation, or capacitor; new construction, upgrade, replacement, or expansion);

(2) The project location, including expected termination points and length for each new transmission line;

(3) the expected design and operating voltage, capacity (MVA) and in-service date;

(4) The approximate cost of each planned expansion or alteration to the transmission network.

ii) The report shall identify constrained regions on the transmission system where new firm generation resources or load reductions can support reliability of the transmission grid.

iii) Information should be provided regarding any other transmission planning initiatives the utility is involved with, if any.

f) Preliminary Optimization Analysis. The IRP report shall identify the least-cost resource plan, assuming perfect information regarding future conditions and assuming that the utility's reference projections occur.

i) This Reference Plan shall include all energy-efficiency resources that are expected to be less expensive than the sum of avoided costs (energy, generation capacity, reserves, emissions requirements, marginal line losses, transmission and distribution) under the Total Resource Cost test.

ii) The optimization analysis may rely on, an expansion planning model that automatically selects resources to minimize costs, given a set of inputs assumptions and operating constraints, such as the system planning reserve margin requirement and any regulatory policies that are in effect at the time the IRP is performed. If it uses an expansion planning model, the utility shall explain how it has checked to ensure that the specific unit sizes, treatment of end effects, and other model inputs have not resulted in uneconomic choices.

iii) The optimization evaluation shall be fully described in the IRP Report.

g) Risk Analyses - The IRP shall include risk analyses for major assumptions that might change the selection of resources in the integrated resource plan, particularly for decisions that would appear in the Action Plan.

i) Sensitivity Analysis—The IRP shall include analyses of the costs of the Reference Plan and alternative resource plans with alternative values of important inputs, to examine the extent to which a each expansion plan might be exposed to unacceptable cost increases under certain conditions. Variables that most likely should be examined include:

(1) fuel prices

(2) loads

(3) capital costs for new generation resources

(4) probable costs of environmental compliance.

ii) Scenario Analysis—The IRP shall include analyses of the costs of the Reference Plan and alternative resource plans under consistent alternative futures, involving changes of multiple inputs from the reference case. For example, high CO_2 prices may be projected to change coal prices, gas prices, load growth, renewables development, and retirement of existing resources. Some scenarios may justify resource changes not considered in the reference case, such as additional transmission options to allow access to lower-cost wind resources.

iii) Flexibility Analysis—To the extent that the sensitivity and scenarios analyses identify critical inputs that would dramatically change the least-cost resource plan, the IRP shall include an analysis of the flexibility of the alternative resource plans to changing conditions. The flexibility analysis shall estimate the cost of starting the resource plan under one set of assumptions (e.g., low fuel) and then finding in a future year (e.g., five years out) that current and forecast conditions have changed (e.g., to high fuel projections), resulting in changing resource plans from that time forward. The flexibility analysis may also consider the effect on various resource plans of price shocks, consisting of abrupt one- to five-year changes in conditions (e.g., doubled gas price, industry-wide nuclear safety shutdowns, drought affecting cooling-water supply, or large recession-related load reductions).

The intention of these analyses is to evaluate the robustness of the alternative resource plans. The risk analyses should be fully described in the IRP Report.

h) Revenue Requirements—The IRP Report shall include projections of annual and present-value revenue requirements, disaggregated by cost category (e.g., generation capital recovery, transmission capital recovery, fuel, energy-efficiency investments) for each candidate resource plan, for the reference case and each risk analysis.

i) Final Expansion Plan Selection Process – The final step in the long-term IRP process is to select the final resource plan based on the optimization analysis, risk analysis, and any other analyses the utility deems necessary. Some judgment may be used in order to examine such factors as the potential exposure of customers to rate shocks, compliance with uncertain alternative-resource mandates and environmental regulations, and the utility's ability to finance the expansion plan. The IRP Report shall discuss the specific methodological approach and decision-making process followed to select the final set of recommended resources in the IRP.

7) Development of the Action Plan

The final step of the IRP process is to develop an action plan, which creates a link between the Company's recommended portfolio and the specific implementation actions that need to be performed during the first five years of the planning period. The action plan should be included in the IRP Report, and at a minimum, should include the following elements:

a) A timetable indicating each important activity or milestone related to any solicitations, permitting process, construction activities, or other important events. This shall apply to potential acquisitions of demand-side and supply-side resources, retirements, life-extension decisions, power-purchase agreements, or any other resource commitments. This information should be provided for any activities that will be underway or planned to take place within the action plan period.

b) A complete description of each activity, including the amount of capacity involved, when the action will be completed, the involvement of other parties (contractors, suppliers, co-owners), and other relevant details.

c) A discussion of any permitting issues or other regulatory actions that are required in order for the resource action to take place.

d) A discussion of the environmental impacts of each resource action (acquisition, continued operation, retirement) and plans to meet all environmental regulatory requirements.

e) Any other information as may be required by the Commission.

8) Collaborative Process and Stakeholder Comments

a) As stated elsewhere in these rules a collaborative process, as authorized shall provide stakeholders with a reasonable opportunity to provide detailed input into the development and final recommendations of IRPs developed under these rules. A general schedule for such collaborative discussions is outlined in Section (10)

b) In addition to participating in collaborative discussions stakeholders shall also have the opportunity to file written recommendations regarding the specific data assumptions and methods to be used in the IRP, as detailed in section (10).

c) Regardless of whether the utility adopts the recommendations, the utility shall include a section in the IRP Report documenting all of the stakeholder's recommendations and explaining the Company's reasons for accepting or rejecting each recommendation.

9) Additional Reporting Requirements

a) In addition to any reporting requirement discussed in any of the preceding sections, the IRP Report shall include a description of the models and all modeling methodologies used, along with the utility's reasons for choosing those models and methodologies.

b) A discussion of any key data assumptions and judgments used in the IRP process not otherwise presented, and an explanation of how those assumptions and judgments were incorporated in the IRP Report. Data assumptions that should be reported, in addition to those specified in preceding sections, include such financial information as the following:

i) The general rate of inflation;

ii) The AFUDC rates used in the plan;

iii) The cost of capital rates (debt, equity, and weighted) and the assumed capital structure;

iv) The discount rates used to determine present worth;

v) Tax rates;

c) The IRP Report shall include full documentation of all analyses leading to recommendations to retire, life-extend or otherwise make major investments in existing generation units. The documentation shall include a complete description of all assumptions, models and results determined from the retirement analysis;

d) All IRP Report filings should include both a public and a confidential version of the Report, as the utility deems appropriate.

10) IRP Schedule

a) Within thirty (30) days of the Commission's issuance of an order in this present docket, each jurisdictional electric utility shall be required to file a simplified IRP Summary Report ("IPSR") that describes its most recently developed long-range resource plan based on whatever resource planning process the utility currently relies on. The Commission does not anticipate that any additional studies will have to be performed to develop this long-range resource plan, as resource planning is already performed on an on-going basis, and it is expected that utilities have already developed such resource plans. This initial IRP Summary Report shall include:

i) a description of the load forecast and forecasting methodology;

ii) a summary of existing resources and transactions;

iii) a description of key input data assumptions;

iv) an explanation of the method that had been used to develop the long-range resource plan, including discussion of the modeling tools that had been used and the studies that had been performed to arrive at the resulting long-range resource plan; and

v) a summary of the key results, including the resulting long-range expansion plan.

b) Staff will review each utility's initial simplified IPSR Report to ensure it contains the required information. Should Staff identify omissions, it will inform the utility. Once the utility addresses the deficiencies, the first filing will be deemed complete the Commission will establish a schedule for comments on the simplified IRP Report. The initial IRP Summary Report and comments will remain on file with the Commission for future reference. The Commission will not hold hearings or issue decisions on the initial IPSR Reports.

After each utility files its first IPSR Report, it will follow the schedule below to start the next IRP cycle. [7] The second, and each successive IRP cycle, will begin by the utility filing with the Commission Secretary a Request to Initiate an IRP Process.

i) The Entergy companies (Entergy Louisiana and Entergy Gulf States Louisiana) shall file on the first business day of January of every even-numbered year.
ii) SWEPCo shall file on the first business day of July of every even-numbered year.
iii) CLECo shall file on the first business day of January of every odd-numbered year.
iv) Each co-operative, either individually or jointly, shall file on the first business day of July of every odd-numbered year.

Each filing shall contain a schedule in accordance with the below table for completing its IRP process. Along with the timeline, the utility shall file data assumptions to be used in the IRP and a description of the studies to be performed. The schedule shall also be published on an IRP website that the utility maintains for communicating information regarding its IRP process. Each successive IRP process will be performed based on a biennial cycle with the utility filing its IRP report at the end of the biennial period.

c) Each IRP Process, as contemplated by this section will be docketed as a Staff-level proceeding that will only be assigned an administrative law judge in the

[7] These dates may be adjusted to coordinate with filing requirements in other jurisdictions.

event of a discovery or procedural dispute, or if so ordered by the Commission.

d) The following table provides the relative schedules to be followed for the IRP process.

<u>Schedule of Events</u>

Event	Description	Number of Months from IRP Filing Date
1	Utility files data assumptions to be used in the IRP (along with a non-disclosure agreement for any confidential data) and a description of studies to be performed	1
2	First Stakeholder Meeting	2
3	Stakeholders may file written data requests	2.5
4	Utility responds to written data requests	3
	Second Stakeholder Meeting	4
5	Stakeholders may file written comments	4
6	Draft IRP report published	9
7	Third Stakeholders Meeting	10
8	Stakeholders may file written data requests	10.5
9	Utility responds to written data requests	11
	Fourth Stakeholder Meeting	12
10	Stakeholders may file comments about draft IRP Report	12
11	Staff files comments about draft IRP Report	13
12	Final IRP Report filed by the utility	14
13	Stakeholders may file written data requests	14.5
14	Utility responds to written data requests	15
15	Stakeholders submit list of disputed issues and alternative recommendations	16
16	Staff submits recommendation to the Commission including whether or not a proceeding is necessary for the resolution of disputed issues	17
17	Commission Order acknowledging the IRP or setting disputed issues for hearing	18

i) Event 1—Subject to appropriate confidentiality safeguards, the utility shall publish the data assumptions and a description of studies it intends to perform as part of the IRP process. This will allow Stakeholders the opportunity to review that information and prepare for meetings with the Company.

ii) Event 2— At least four collaborative stakeholder meetings will be held during the IRP cycle. Stakeholders will meet with the utility to discuss the initial data inputs for the base and sensitivity cases, as well as the utility's proposed analytical process. This will allow stakeholders the opportunity to collaborate in the development of the IRP by suggesting alternative assumptions and approaches and bringing additional information to the utility's attention. In addition to scheduled collaborative meetings, the utility is encouraged to collaborate with stakeholders informally throughout the IRP process.

iii) Events 3 & 4— Stakeholders shall have the opportunity to submit written questions approximately two weeks after the first IRP meeting and receive responses approximately two weeks prior to the first written recommendations.

iv) Event 5—Stakeholders shall have the opportunity to file written recommendations regarding the specific data assumptions and methods to be used in the IRP.

v) Event 6—The utility will conduct its initial IRP analysis and write its IRP Report. The deadline associated with this event is the date utility shall publish its Draft IRP Report.

vi) Event 7—Stakeholders shall have the opportunity to meet with the utility to discuss the Draft IRP Report.

vii) Events 8–11—Stakeholders and Staff shall have the opportunity to review the Company's Draft IRP Report and file comments. Staff's review is primarily intended to determine whether the utility met the requirements established in these IRP rules. However, Staff shall not be limited by the requirements and may provide additional comments if it deems it appropriate to do so. Staff may also take the Stakeholders comments into consideration as it develops its own comments.

viii) Event 12—The Final IRP Report will reflect any changes that the utility makes in response to recommendations in Staff's and Stakeholders comments. The utility will be free to implement any changes to its IRP process that it chooses to, as recommended by Staff or the Stakeholders; however, the utility will be under no obligation to do so. Regardless of whether the utility chooses to implement any changes, the utility will be required to include a section in the Final IRP Report documenting all of Staff's and the Stakeholder's recommendations, and explaining the Company's reasons for accepting or rejecting each recommendation. Any changes to the Draft IRP Report made in response to Stakeholder or Staff's comments, or any other changes made by the utility to the Draft IRP Report, should be clearly identified in some manner such as by providing a redline version of the Final IRP Report.

ix) Events 13 & 14— Stakeholders and Staff request any additional information they need to formulate their recommmendations.

x) Events 15 & 16—Stakeholders will identify any areas in which they disagree with the Final IRP Report. Staff will either recommend that the Commission acknowledge the IRP filed by the utility, or recommend a resolution of disputed issues.

xi) Event 17—If the Commission determines that there disputed issues it will need to resolve, it will establish a procedural schedule. Once all issues are resolved by negotiation or Commission order, the Commission will be provide an acknowledgement that the utility's IRP process and its IRP Report have fully complied with the requirements of these IRP rules. That acknowledgement will not constitute Commission approval of the IRP conclusion. The Commission may also, at its discretion, provide directives to the utility for improvements to the utility's IRP inputs and process, including the results in the IRP Report. Any such directives may be considered in any future Commission proceedings concerning the resource plans of the utility.

10) Integrated Resource Plan Update

a) The utility <u>may</u> submit an update to its IRP plan prior to the required submission of its next IRP if:

i) It anticipates submitting an application for a certificate to construct or purchase a supply-side or demand-side resource that was not previously included as part of the IRP;

ii) It anticipates the need to release an RFP for a demand-side or supply-side resource, which was not previously included as part of an integrated resource plan;

iii) The basic data used in the formulation of its last IRP requires significant modification that affects the choice of a resource or use of an RFP that was included as part of the integrated resource plan; or

iv) The Commission or utility finds that other conditions warrant amendment of the utility's IRP. The conditions under which such an amendment is sought shall be specifically set forth in the application for amendment.

b) Each utility shall determine which components of the IRP analysis to incorporate in its update, so long as it responds to any issues raised by the Commission.

c) The filing of an IRP update does not replace the utility's obligation to file a new, complete IRP every two years.

11) Amendments to these IRP Rules

These Rules may be amended at any time by the Commission as it deems necessary.

12) References that were relied upon in developing these rules:

a) Georgia State Code - O.C.G.A. § 46-3A-1 – Chapter 3a covers Integrated Resource Planning - (http://www.lexis-nexis.com/hottopics/gacode/default.asp Search for 46-3a)

b) Georgia Public Service Commission Rules – IRP Rules - 515-3-4 (http://rules.sos.state.ga.us/cgi-bin/page.cgi?g=GEORGIA_PUBLIC_SERVICE_COMMISSION%2FGENERAL_RULES%2FINTEGRATED_RESOURCE_PLANNING%2Findex.html&d=1)

c) Utah Public Service Commission Order – Docket No. 90-2035-01 – Report and Order on Standards and Guidelines Concerning an Integrated Resource Plan for PacifiCorp – June 18, 1992. (Available as a word document)

d) Arkansas Resource Planning Guidelines for Electric Utilities – Approved in Docket 06-028-R, January 4, 2007 (http://www.apscservices.info/Rules/resource_plan_guid_for_elec_06-028-R_1-7-07.pdf)

e) Comments of Parties filed in this docket - LPSC Docket R-30021 – November 13, 2007

f) Technical Conference – LPSC Docket R-30021 - May, 12, 2008

EXHIBIT

AAE-2

AAE-1

Proposed Integrated Resource Planning Rules

For Electric Utilities ~~In~~in Louisiana

1) Overview

The following Integrated Resource Planning ("IRP") Rules shall be used by jurisdictional investor owned and cooperative electric utilities regulated by the Louisiana Public Service Commission ("Commission" or "LPSC") to develop long-term Integrated Resource Plans ("IRP"), which include both supply and demand-side resources, and considers transmission impacts, in order to satisfy the utility's load requirements. An electric utility's IRP shall be relied on by the utility as it creates its internal business plans. These rules are intended to provide utilities the flexibility to develop plans that meet their own specific needs and circumstances, to encourage a collaborative working process with all stakeholders, and to be consistent with the requirements of the Commission's Market Based Mechanism Order ("MBM")[1] and the 1983 General Order.[2]

Resource planning under these rules does not change the fundamental relationship between the utilities and the Commission. The Rules do not mandate a specific outcome nor do they mandate any specific investment decisions to be made. Resource planning should reflect each utility's unique circumstances and the judgment of its management, and each utility will continue to bear the full responsibility for the consequences of its decisions. Resource planning decisions made as part of the utility's IRP process will be relevant to future investment decisions and approval proceedings, as well as revenue requirement and rate design proceedings. Consistency of a utility's Integrated Resource Plan with these Rules will be an additional factor for the Commission to consider in evaluating the prudence of investments in construction and rate application proceedings. Any changed circumstances that occur after the IRP has been developed should also be considered in those proceedings.

2) Definitions

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[1] General Order, Docket No. R-26172 Subdocket A, *In re: Development of Market Based Mechanisms to Evaluate Proposals to Construct or Acquire Generating Capacity to Meeting Native Load, Supplements the September 20, 1983 General Order,* dated February 16, 2004 (as amended by General Order, Docket No. R-26172 Subdocket B, dated November 3, 2006, by the April 26, 2007 General Order, as referred to as the "MBM General Order", and further amended by the General Order, Docket No. R-26172 Subdocket C, dated October 29, 2008)

[2] General Order, *In re: In the Matter of the Expansion of Utility Power Plant; Proposed Certification of New Plant by the LPSC,* dated September 20, 1983, as amended by the General Order in Docket No. R-30517 dated October 29, 2008, and corrected May 27, 2009.

a) Allowance – In conjunction with environmental legislation, an allowance provides an entity the right to emit a certain amount of emissions. With regard to SO2 provisions in the Clean Air Act Amendments of 1990 (PL 101-549) at Title IV (known as the Acid Rain Program), one allowance give a utility the right to emit one ton of SO2. Allowances may also be considered in conjunction with other pollutants such as NOx, C02 and similar greenhouse gas emissions, and mercury.

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b) Avoided Cost –

i) Avoided energy costs are the fuel ~~and~~ , variable O&M expenses and other costs (including commitments to fixed costs) a utility avoids by, for example, ~~by~~ purchasing energy from another party or ~~by relying on energy efficiency to reduce~~reducing energy consumption.– through energy-efficiency programs. Avoided energy costs will vary by season and time of day, and will typically be higher for load-following load shapes than baseload resources.

~~b)~~ii) Avoided generation capacity costs reflect the value to the utility and its customers of reducing peak loads and the need for capacity peaking-equivalent of the portion of the cost of new generation ~~facilities~~resources, or the market value of freeing up existing that could be avoided, for example, by reducing peak demand as a result of a demand-side management program. Avoided generation capacity costs for energy efficiency include the reserve margin avoided by load reductions.

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iii) Avoided transmission and distribution costs reflect the expected value of investments avoidable or deferrable by load reductions, generally estimated from the long-term ratio of historical or projected investments to load growth in the same period.

~~c)~~iv) All avoided costs must include avoided losses from the end use back to the level at which the avoided cost is estimated (e.g., energy at generation).Cogeneration - Production of electricity by a Qualifying Facility, which the utility is required to purchase, as defined in the Public Utility Regulatory Policies Act ("PURPA") of 1978, at 16 U.S.C. Section 796. Additional policies concerning PURPA requirements were addressed in the Energy Policy Act of 2005, Title XII, Subtitle E, Section 1253, and in the Energy Independence and Security act of 2007, Section 515.

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~~d)~~c) Commission – ~~Refers to the~~The Louisiana Public Service Commission.

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d) Collaborative Working Process - A process, authorized by the Commission, in which utility and non-utility stakeholders have an opportunity to provide detailed input into the development, and final recommendations, of the Integrated Resource Plans developed under these rules. Such a process is intended to provide an informal, but substantial, venue in which a reasonable balance between private and public interests can be identified and incorporated, if possible, within the final IRP plans.

e) Demand Response – Load-management programs that have the intended goal of reducing load during the actual hours with high energy costs and/or supply problems.

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~~e)~~f) Demand-side:

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i) Energy-efficiency measure - any device, technology, or operating procedure that makes it possible to deliver an equivalent level and quality of end-use energy service while using less energy or peak demand than would otherwise be required.

ii) Management ~~–Load control programs, such as air conditioning~~ Energy efficiency and load-management programs. ~~Note that~~

~~i)~~iii) Market Segment - A portion of the ~~term "demand-side management" is often used in~~ potential DSM market, with common characteristics which may require a ~~more general way to refer~~unique approach to ~~all load management programs.~~ DSM program design or implementation. Market Segments are generally differentiated by customer class (residential, small C&I, large C&I), other customer distinctions relevant to delivery methods (e.g., low income, multi-family, rental, non-profit, government, food-service) and market opportunity (new construction and renovation, routine equipment replacement, early replacement, and retrofit).

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~~ii)~~iv) ~~Measure – An individual project consisting~~Portfolio - The totality of the ~~hardware, equipment or a practice, which is installed or instituted for~~ utility's efforts to promote end-use energy efficiency ~~or load management purposes~~.

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v) Potential studies - Studies conducted to assess energy savings potentials for different technologies and customer markets. Potential is typically defined in terms of technical potential, market potential, and economic potential.

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~~iii)~~vi) Program – ~~This is a collection of demand-side measures~~A coordinated set of tools - including marketing, outreach, training, delivery, incentives, verification and evaluation - addressing the needs of

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Formatted: Indent: Hanging: 0.38", Tab stops: 0.88", List tab a particular market segment, designed to ~~operate as a single program, which serves to~~ reduce a utility's capacity and/or energy requirements.

~~f) Demand Response – Load management projects that have the intended goal of reducing load during the peak hours.~~

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g) Energy Efficiency - ~~Conservation programs.~~The provision of the same energy services (light, warmth, cooling, industrial output, etc.) while using less energy, such as home insulation measures. ~~Note that the term "energy efficiency" is also often used in a general way to refer to all load management programs.~~

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h) Externalities - Environmental and social costs or benefits that result from the production or delivery of energy, and ~~arise separate from~~are not reflected in the ~~energy sale transaction between~~prices paid by the utility and ~~the customer~~its customers.

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i) Integrated Resource Planning – A type of utility planning process that develops long-range ~~expansion plans considering all feasible combinations~~resource plans, seeking the optimal combination of resources ~~on a consistent and comparable basis~~ (including demand and supply-side options~~). Expansion plans are developed to meet load~~) that meets forecast requirements at the lowest ~~reasonable~~ total cost, subject to reliability, planning, environmental and operational constraints~~. At times, a utility may select resource options that are not exclusively least cost if the utility is able to demonstrate that those resources will reduce~~ and the value of risk ~~of customers incurring higher costs under certain scenarios.~~ reduction.

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j) IRP Report - The document ~~that describes how~~describing the resources that the utility plans ~~to supply resources, both reliably and economically~~, in order to meet its forecasted load requirements~~.~~ both reliably and economically. The report should fully describe input data assumptions used, modeling methodologies relied on, evaluations performed, results produced, and conclusions reached, with regard to the selection of the utility's long-term resource plan.

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k) Load Management - Measures and programs that curtail or shift loads from high-cost or high-demand periods. Load-management programs include direct load control (such as of air conditioners and water heaters), demand response involving two-way communications reflecting actual conditions, and interruptible rates.

l) Lost-opportunity efficiency resource - An energy-savings opportunity tied to a transient market opportunity, such as designing and building a new building; major renovations and expansions of buildings and production lines; replacing failed, failing and obsolete equipment; and purchasing new equipment.

~~k)~~m) Planning Period – The ~~overall~~period for which the plan projects resource requirements. The default planning period for the IRP is ~~recommended to be~~ 20 years~~. While a 20 year planning period is recommended. a~~, but the utility may use ~~an alternate~~a shorter period, if it can provide justification supporting ~~its~~the use~~.~~ of that period and demonstrate that end effects have been adequately reflected. Such justification should be included in the utility's IRP Report. In addition, a five-year Action Plan should be created and included as part of the IRP Report. The Action Plan should describe the specific actions that the utility expects to take during the first five years of the planning period in order to fulfill the requirements of the IRP.

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n) Probable environmental cost: means the expected cost to the utility of complying with new or additional environmental legal mandates, taxes, or other requirements that, in the judgment of the utility decision-makers, may be imposed at some point within the planning horizon which would result in compliance costs that could have a significant impact on utility rates

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o) Program Evaluation: The performance of studies and activities aimed at determining the effects of a demand side program; any of a wide range of assessment activities associated with understanding or documenting program performance, assessing program or program-related markets and market operations; any of a wide range of evaluative efforts including assessing program-induced changes in energy efficiency markets, levels of demand or energy savings, and program cost effectiveness.

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~~l)~~p) Power ~~purchase~~Purchase – A transaction to purchase capacity and or energy from another electric power supplier that will partially satisfy the utility's load requirements. Power purchases can encompass different time periods, as follows:

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i) Short term – A purchase of ~~oneyear~~one year or less, ~~and as such,~~which is not required to be procured pursuant to a RFP, as set forth in the Commission's MBM Order.

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ii) Long Term – A purchase that lasts more than one year, ~~and~~ which must satisfy the Commission's MBM Order requirements.

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~~m) Screening Tests: These are evaluations that should be performed to determine which demand and supply side~~Retrofit efficiency resource ~~options should be eligible for further consideration in~~ - An opportunity to increase the ~~remaining steps~~efficiency of ~~the utility's IRP~~a building, equipment, process~~.~~

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~~Demand side screening should be performed based on industry standard screening tests such as the California Standard Practice Tests. The California Public Utility Commission has published guidelines for evaluating DSM~~

~~programs in its *Standard Practice for Cost Benefit Analysis of Conservation and Load Management Programs*, which was first published in February 1983, and most recently updated in 2001.[3] The manual defines the following standard tests:~~

- ~~*Participants Test* — This test measures the *quantifiable* benefits and costs to the customer. The *benefits* to a customer include the reduction in the customer's utility bill (using the retail rate), any incentives paid by the utility, and any~~ , or other ~~benefits to the customer that~~end use by adding to or replacing existing plant or equipment, or changing procedures. By their nature, retrofits can be ~~quantified. Savings estimates should be based on gross energy savings, as opposed to net savings.[4] The *costs* to a customer are all out of pocket expenses incurred, plus any increases in the customer's utility bill. The out of pocket expenses include all costs of purchasing and installing equipment or materials, any ongoing operation and maintenance costs; any removal costs (less salvage value); and the value of the customer's time in arranging for the installation of the measure, if significant.~~

q) ~~*The Ratepayer Impact Measure (RIM)* — This test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Rates will go up if revenues collected are less than the~~implemented earlier or later, to minimize total costs ~~incurred by the utility in implementing the program. The *benefits* calculated in the RIM test are the savings from avoided supply costs. These avoided costs include the reduction in transmission, distribution, generation, and capacity costs for periods when load has been reduced, and includes the increase in revenues for any periods in which load has been increased. Both the reductions in supply costs and the revenue increases should be calculated using net energy savings.~~and promote efficient implementation.

~~The *costs* for this test are the program costs incurred by the utility, the incentives paid to participants, decreased revenues for any periods in which load has been decreased, and increased supply costs for any periods when load has been increased. The utility program costs include initial and annual costs, such as the cost of equipment, operation and maintenance, installation, program administration, and customer dropout and removal of equipment (less salvage value).~~

~~*Utility Cost Test* measures the net costs of a demand side management program based on the costs incurred by the utility. The *benefits* are the avoided supply costs of energy and demand, the reduction in transmission, distribution, generation, and capacity~~

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[3] ~~http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF~~

[4] ~~Gross energy savings are the savings in energy seen by the participant at the meter. These are savings assumed to be attributable to the program. Net savings are gross savings minus changes in energy use and demand that would have happened even if the DSM program were not implemented.~~

~~valued at marginal costs for the periods when there is a load reduction. The avoided supply costs should be calculated using net program savings.~~

~~The *costs* for the Utility Cost Test are the costs incurred by the utility, including the incentives paid to the customers, increased supply costs for the periods in which load is increased, program costs, which include initial and annual costs, such as the cost of utility equipment, operation and maintenance, installation, program administration. and costs due to customer dropout and removal of equipment (less salvage value).~~

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- ~~*The Total Resource Cost Test* measures the net cost of a demand side management program based on the total costs of the program. including both the participants' and the utility's costs. The *benefits* calculated in the Total Resource Cost Test are the avoided supply costs, the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction. The avoided supply costs should be calculated using net program savings. The *costs* in this test are the program costs paid by the utility and the participants plus the increase in supply costs for the periods in which load is increased. Thus all equipment costs, installation. operation and maintenance. cost of removal (less salvage value). and administration costs. no matter who pays for them. are included in this test. Any tax credits are considered a reduction to costs in this test.~~

~~Supply side screening should also be based on industry standard methods. A common practice in screening supply side alternatives is to compare alternatives based on a levelized cost or a present value analysis of revenue requirements over the life of the resource at varying levels of operation or capacity factor.~~

~~n)~~r) Stakeholders~~: This includes customers of the utility~~ - Individuals or other entities which have a reasonable likelihood of being significantly affected by the electric resource investments considered within the IRP process. Among other parties, this includes representatives from regulatory agencies, utilities, customers of such utilities, and consumer and environmental advocacy groups that are duly constituted and organized as such.

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~~o)~~s) Supply~~-side Capacity Option-~~ Resource - An electric generating unit, either owned and/or operated by the utility~~,~~ or a ~~capacity~~ portion of such unit; or a purchase~~,~~ of capacity and/or energy from one or more such units or from the seller's system supply. Supply Resources may include upgrades or life extension for existing units or plants.[5]

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[5] It may also be appropriate to treat as separate resource options some major transmission projects that could provide access to economic generation resources either from outside the utility's service territory or between zones within the service territory.

~~p)~~t) Utility - any electric utility furnishing service within the State of Louisiana and subject to the jurisdiction of the Commission.

3) Overview of the IRP Process

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~~The general process that must be followed in developing the IRP:~~

a) The overall objective is to develop a base case IRP based on the most economic and reliable combination of resources, including supply~~-side~~, demand-side and ~~economic~~ transmission resource options, in order to satisfy the forecasted ~~load~~energy-service requirements.[6] All constraints such as reliability and environmental requirements ~~will have to~~must be accounted for in the planning process. The planning process shall include, at all stages, a reasonable level of participation by a collaborative process as authorized by the Commission.

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b) A ~~load~~ forecast ~~should~~of peak load and energy requirements shall be developed as the first step of the IRP process. The load forecast ~~should~~ shall be developed covering the IRP planning period, and shall identify the effects of non-utility energy activities that may affect the level of future energy consumption or peak demand. These would include, for example, lighting- and appliance-efficiency standards and improved building energy codes.

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c) The Plan shall assess the condition of all existing supply and load-management resources, including existing purchase and sale transactions~~—should be assessed.~~. Any ~~planned~~committed additions and retirements—those that are fixed by contract or regulatory requirement—should be identified~~.~~, along with any anticipated reratings. For each existing generation resource, the utility shall provide estimates of the costs of keeping the resource in service, including fixed O&M, routine capital additions, and environmental compliance. Where the utility cannot reliably estimate the costs of compliance with existing or pending environmental regulations, the IRP should include a description of those regulations and the range of potential requirements and costs.

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d) ~~A~~The utility shall determine the resource capacity required to serve its forecast loads. That determination may be based on the rules and requirements of the relevant planning authority or on a system reliability assessment~~ may be performed to determine the forecasted reliability of the system.~~, reflecting the utility's loads, resources, and interconnections. The end result of the reliability

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[6] ~~Typically all~~Most new central generation resources will require transmission interconnection and integration costs~~ and those costs~~, which should be ~~considered in~~treated as part of the ~~analysis. At times, there may be large transmission projects that could provide access to economic generation resources, and it may be desirable to treat those projects as separate~~ cost of the resource~~ options in the optimization process.~~

assessment is the determination of ~~a~~ target reserve ~~margin~~margins to be used in the IRP process.[7]

e) ~~The utility's~~ The utility shall estimate future resource needs ~~must be determined. This evaluation considers~~, as the product of the planning reserve margin target~~, the load~~ times forecast~~,~~ peak load, minus the existing supply and ~~demand-side~~load-management resources~~,~~ adjusted for any ~~planned~~committed additions and retirements (both supply and demand-side~~),~~ ~~and it determines the utility's capacity needs~~). Any positive difference reflects a need for peak-demand resources over the planning period.

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f) ~~To satisfy~~The utility shall identify all resource alternatives that may potentially be cost-effective in meeting the utility's peak resource needs or reducing total costs or risks over the planning period~~, all potentially viable resource alternatives should be identified. This includes both~~. Resources to be considered would include conventional ~~and non conventional resources (for example,~~ central thermal generation, renewable generation, and cogeneration; distributed generation; utility-owned and non-utility resources; energy-efficiency programs; load-management options~~), demand side alternatives,~~; and transmission upgrades that provide access to potentially economic supply-side resources. The remainder of the IRP process ~~contains~~consists of the data, tools, and methodologies~~, and consistent data sources that are~~ needed to evaluate these ~~resources~~resource alternatives in an appropriate manner.

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g) ~~A screening process should be employed in order to narrow~~The plan shall describe the ~~list~~development of ~~options, given~~ the ~~large number of~~ energy-efficiency portfolio, which shall include all cost-effective and feasible lost-opportunity resources plus the majority of feasible cost-effective retrofit resources over the Planning Period.

h) The plan shall describe the utility's analysis of distributed-generation program options, including the potential ~~alternatives that~~for distributed generation to reduce line losses and avoid T&D investments, as well as the utility's programs for encouraging development of distributed generation in the most beneficial areas and for facilitating the installation of customer-owned distributed generation.

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i) The ~~likely will be identified~~plan shall include a comprehensive description of the utility's programs and policies to reduce losses in the ~~prior step. In the case of~~ T&D system, including:

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[7] The Plan should be clear as to the nature of the peak load from which the reserve margin is computed (e.g., normal or extreme weather; the utility, holding-company or regional peak).

i) Policies and guidelines for selecting new conductors and transformers to minimize total costs, including energy and capacity losses at marginal costs.

ii) Programs for determining where loss reductions justify reconductoring or upgrading feeder voltage; replacing transformers before failure; and adding capacitors.

~~g)~~j) If the utility identifies many potential supply~~-side~~ alternatives, it shall select a manageable number of the most promising options~~, a~~. A screening process is particularly helpful when there are several similar choices of generation technologies available~~. In the case of demand side options, a screening process is necessary as hundreds of potential demand side measures may be identified for further evaluation.~~ (e.g., sub-critical, super-critical, fluidized bed, and IGCC coal) All resource options that have not been excluded by the screening process should be considered further in the ~~next step of the~~ utility's IRP process.

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~~The next step of the IRP process is an optimization analysis in which all alternatives are evaluated including supply side, demand side and economic transmission options. The optimization process allows all resources to be considered on a level playing field and results in the most economic set of resources being selected over the planning period subject to all constraints. Normally, the long-term expansion plan that meets all constraints (e.g.~~

~~h)~~k) The utility shall construct a reference expansion plan that meets all constraints (e.g. reliability, environmental, etc.), and has the lowest net present value revenue requirement, considering all relevant costs (fuel, O&M, capital and environmental~~), is considered the optimal plan at this stage of the analysis.~~). The reference plan shall include all cost-effective lost-opportunity and loss-reduction resources, plus retrofit resources at the maximum efficient pace and additional distributed and central-station generation as necessary to meet requirements.

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~~i)~~l) The next step is to conduct ~~sensitivity and scenario analysis.~~ risk analyses. The purpose of ~~this analysis~~these analyses is to ~~examine specific scenarios~~determine whether a change in the resource plan will reduce vulnerability to higher bills or ~~to consider the impact~~higher revenue requirements as a result of ~~specific variables in a sensitivity analysis~~reasonably foreseeable changes in inputs.

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~~j)~~m) The ~~next step is to~~utility shall select the final preferred expansion plan portfolio, reflecting expected total cost to customers, risk, uncertainties, environmental and other considerations.

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~~k)~~n) The final step of the IRP process is to develop an ~~action plan, which~~Action Plan that details the specific activities the utility ~~should~~expects to take to implement the IRP during the first five years of the planning horizon.

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The following sections provide more detailed requirements regarding the development of the IRP, including reporting requirements that must be documented in the IRP Report.

4) Energy and Peak Demand Forecast

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This section describes in additional detail the load forecast requirements, and explains the information that must be included in the IRP Report concerning both the utility's actual historical load and its forecasted load. The utility shall define the type of peak load reported (e.g., operating company peak, contribution to holding-company peak, contribution to pool or other area peak), and clearly differentiate among retail and wholesale loads.

a) Time Frame

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i) ~~Historic Data. Energy and~~ Historical energy requirements and peak demand ~~historic results~~ should be reported covering at least the ~~three~~ten years prior to the first year of the IRP planning period~~.~~ and for at least the time period used in constructing the forecast.[8]

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ii) Forecast period. ~~All energy~~Energy and peak demand ~~forecasts~~ should be ~~performed~~forecast for each year of the IRP planning period.

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b) Energy and Demand Information Supplied in the IRP Report

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i) Historic load data ~~should be provided for the three years preceding the start of the IRP planning period,~~ shall include the following, in both actual and weather-normalized terms (including the ~~following:~~methodologies and processes used to normalize for weather):

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(1) The total annual energy consumption for electricity for the utility and for each of the utility's customer classes;

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(2) The summer, winter and annual coincident peak demands for the utility and for each of the customer classes, ~~if available~~to the extent the utility has developed such estimates by customer class;

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(3) Monthly energy consumption for the utility and for each of the customer classes;

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(4) Annual load factor for the utility and for each of the customer classes, if available by customer class.

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[8] For example, if the forecast is based on twenty years of historical data, the Plan should provide those data.

(5) To the extent any historical data differ from previous filings (e.g., FERC Form 1, p. 402), the utility shall explain the differences.

ii) Previous Forecast Evaluation. Each IRP Report ~~should~~shall contain an evaluation of ~~the previous~~ peak demand and energy ~~forecast since the last~~ forecasts produced by the utility in the five years prior to the filing of the IRP ~~Report was filed and should include~~, including the following:

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(1) An assessment of the accuracy of the previous ~~forecast~~forecasts;

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(2) An explanation of the cause of any significant deviation that occurred between the prior forecast and the actual peak demand and energy;

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(3) An explanation of revisions to subsequent load forecast methodologies and assumptions utilized to correct for prior deviations in the prior load forecast.

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(4) An explanation of the impact that demand-side programs~~ and~~, interruptible load or modified energy codes or standards had on the prior load forecast.

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iii) Forecast Load Data~~.~~: The ~~load forecasts should be weather normalized and the~~ IRP Report ~~should~~shall include the following information:

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~~(1) The methodologies and processes used to normalize for weather should be fully described and justified.~~

~~(2)~~(1) The total annual weather-normalized energy consumption of electricity for the utility and for each of the utility's customer classes;

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~~(3)~~(2) The summer, winter and annual coincident peak demands for the utility and for each of the customer classes, if available by customer class;

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~~(4)~~(3) Monthly energy consumption for the utility and for each of the customer classes;

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~~(5)~~(4) Annual load factor for the utility and for each of the customer classes, if available by customer class.

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iv) ~~Projected~~ Forecast ~~Evaluation.~~Documentation. Each IRP Report ~~should~~shall contain an evaluation of the projected peak demand and energy forecast ~~and should include~~, including the following:

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(1) ~~A discussion~~Description and full documentation of the ~~load~~econometric or end-use forecasting ~~methodology used in the IRP. The utility should explain the methodology~~models utilized, including a demonstration that ~~was used and should discuss how it~~the approach is consistent with or superior to typical utility industry load forecasting practice.

(2) The historical data used to estimate, calibrate or validate the model.

~~(1)~~(3) Projections ~~The utility should explain the significant determinant~~of all variables ~~that were incorporated in~~driving the ~~load~~power forecast ~~process.~~ (e.g., measures of economic activity, customer number, power prices, efficiency standards) and the sources of those projections.

~~(2)~~(4) ~~It should describe~~A quantification of the impact that demand-side programs, energy codes and standards and interruptible loads had on the load forecast.

~~(3)~~(5) ~~It should discuss~~Documentation of the amount of losses included in the forecast, ~~and should discuss any actions~~including the extent to which the forecast includes the effects of current and planned ~~to reduce losses in the future.~~loss-reduction programs.

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5) Existing Resource Evaluation

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This section describes in additional detail the existing resource evaluation, and discusses information that must be included in the IRP Report.

a) Existing Resources. The utility should evaluate and discuss in its IRP Report ~~all~~capacity and energy available and expected from each existing ~~resources~~resource, including ~~power~~

i) Utility-owned generation,

ii) Power purchases from any supplier,

iii) Unit-specific sales and ~~exchange~~any other sales not reflected in the load forecast,

iv) Exchange energy, ~~demand-side resources, pooling~~

v) Pooling or coordination agreements that reduce resource requirements,

vi) Load management programs and interruptible contracts, and

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vii) Anyany other supply or demand-side resources.

~~a)~~ The utility ~~should~~shall also describe any important changes to the resources that occurred since the last IRP Report was filed ~~or expected to occur prior to when the next IRP Report will be filed.~~. Any program evaluation research or reports which quantify the savings of utility demand side programs shall also be provided and briefly summarized.

b) Existing ~~Supply Side~~Generation Resources. —The following ~~supply side resource~~ data should also be supplied for each utility-owned or unit-specific resource:

i) Resource type

ii) Capacity

iii) Fuel type, efficiency and costs

iv) Fixed and variable O&M

~~iv)~~v) Ownership information

~~v)~~vi) Location

~~vi) Age and anticipated life remaining~~

~~vii) Condition of the resource~~
vii) Commercial operation date

viii) Condition of the resource, and for any resources expected to retire (or any purchases expected to end) within the next ten years, expected retirement date and an explanation of the basis for the expected retirement

c) Existing Demand-Side Resources. The following ~~demand side resource~~ data ~~should~~shall also be supplied for each existing energy-efficiency and load-management program:

i) Program ~~or measure~~name and description

ii) Market segment addressed, including customer class(es) included; end uses, business type, or building type targeted; whether addressing new construction, routine replacement, or retrofit market.

~~ii)~~iii) Start date and anticipated program life remaining

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~~iii)~~iv) ~~Capacity~~Historical results, including level of customer participation; level of measure penetration; and estimated capacity, energy and cost savings achieved

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~~iv) Customer class~~

~~v) Level of participation~~

v) Any program evaluation research or reports which quantify the savings of utility demand side programs shall also be provided and briefly summarized.

vi) Levelized costs of energy savings achieved

vii) Identification of avoided costs used in demand side cost effectiveness analysis, the date and methodologies used in developing these avoided costs

viii) Nature of program process and impact evaluation, including evaluation schedule and citations to all completed and pending evaluation reports.

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~~vi) Any other relevant information~~

d) Existing Transmission System~~—~~. The following transmission system data ~~should~~shall be supplied:

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~~i)~~ A ~~ten year~~ list of existing and approved transmission ~~plan should be provided containing details of all approved and proposed projects. The ten year plan should consider all transmission projects at or above the 115 kV level. Details of all planned transmission projects should include at least the following:~~

~~(1) the expected termination points and length~~lines, identifying for each ~~new transmission line;~~

~~(2) identification of existing transmission facilities planned for upgrade, rebuilding or retirement;~~

~~(3)~~i) ~~the expected design and~~ origin, terminus, operating and design voltage, length, number of circuits, size and material of conductor, and maximum capacity (MVA~~) and in-service date for each new, upgraded or rebuilt transmission facility;~~).

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~~(4)(1) The approximate cost of each planned expansion or alteration to the transmission network.~~

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~~Information regarding preferred regions on~~

ii) A list of existing and approved substations, identifying for each location, voltages, and the number and capacity of transformers for each voltage combination.

~~ii)~~iii) The topology of the transmission system ~~where interconnection of new firm resources can support reliability of the transmission grid~~, in maps, diagrams and/or other formats.

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~~iii)~~i) ~~Information should be provided regarding any other transmission planning initiatives the utility is involved with, if any.~~

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6) Development of the Integrated Resource Plan

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This section describes in additional detail the development of each utility's IRP, and discusses information that must be included in each utility's IRP Report.

a) System Reliability Assessment. ~~A~~ The utility shall determine the resource capacity required to serve its forecast loads. That determination may be based on the rules and requirements of the relevant planning authority or on a system reliability assessment ~~may be performed to determine the forecasted~~, reflecting the utility's loads, resources, and interconnections. The system reliability ~~of the system. It is common in the utility industry to rely on a one day in ten year loss of load probability ("LOLP") criteria, and to conduct an LOLP study to evaluate~~assessment would estimate the reliability of the ~~utility~~ system ~~against the established criteria. Generally, an additional analysis is performed to identify the equivalence between the system's loss of load probability and its target reserve margin. For example, for some generic utility, a one day in ten year loss of load probability may be determined to equate to a reserve margin target of 14%. In some cases, the utility may not need to perform a System Reliability Assessment as it is part of a~~ with existing and committed resources and projected load, and determine the amount of generic capacity (if any) that must be added to maintain the reliability ~~coordinating group and is obligated to meet a pre-specified reserve margin target. The utility should document in its~~criterion. If the utility conducts a system reliability assessment, it shall specify the reliability criterion selected, which may be one-day-in-ten-year loss-of-load probability ("LOLP"), or a similar loss-of-load or unserved energy expectation criterion. The utility shall explain how the verbal criterion was implemented as a numerical target (for example, whether one day in ten years is interpreted as 24 hours of shortage per 87,600 hours, or one hour of shortage per 87,600 hours). The IRP Report~~,~~ shall document the final reserve margin target ~~it~~ used

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~~in its IRP process,~~ and provide complete details regarding how ~~it arrived at~~ the target~~. This documentation should include~~ was derived, including a description of any analysis that was performed, the data and assumptions that were used, and the results of the reliability assessment.

b) Resource Needs Assessment – A resource needs assessment should be performed considering the planning reserve margin target, the load forecast, the existing supply and ~~demand-side~~load-management resources, and any ~~planned~~committed additions and retirements (both supply and demand-side). The result of the resource needs assessment ~~includes~~will indicate the utility's capacity needs for peak demand over the planning period.– The utility's resource needs assessment should be fully described in the IRP Report.

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c) Demand-Side Resource Analysis

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i) ~~A~~ The utility shall provide and summarize the estimates of any Louisiana specific energy efficiency (DSM) potential studies which have been conducted subsequent to the last IRP filing. The utility shall also demonstrate how the results of such studies have been incorporated within its proposed portfolio of energy efficiency programs. If no such potential studies have been conducted or updated within the prior four years it shall be the responsibility of the utility to conduct such a study or update and ensure that stakeholders have an opportunity to provide input into the development and findings of such research.

ii) The utility shall identify a range of cost effective and comprehensive demand-side ~~measures should be evaluated~~programs that collectively will address all market segments and allow all customers to participate in energy-efficiency programs. Such programs shall be designed and implemented in conformance with national "best practices" for such programs.

iii) Separate programs shall be identified to address new-construction, routine-purchase and retrofit opportunities for all significant customer and market sector groups.

iv) Separate programs shall be identified for each ~~customer class. The utility should compile a thorough list of measures based on an inventory of~~ distinct customer group or market segment with significant levels of cost effective savings potential Those groups will vary by utility, but are likely to include residential, small commercial, large commercial and industrial, and outdoor lighting. It may also be appropriate to include separate programs for farms (due to their distinct end~~-use devices.~~ uses), low-income customers and/or renters (due to the special challenges of reaching these customers), mobile homes (due to their specific technologies), governmental and institutional customers (due to their specific financing and approval issues), large industrial customers (due to the complexity of improving process efficiency), specific industries or business types, or other groups.

~~i)~~v) For each ~~measure on this list~~program, the ~~utility should include in its~~ IRP Report shall include the following information:

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(1) The class(es) and market segment targeted by the program.

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~~(1)~~(2) A description of the ~~measure;~~range of measures and projects that are or would be covered by each program.

(3) Actual and proposed incentive structures, and an explanation of why the utility believes that the incentives would promote appropriate levels of participation.

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(4) Projections of ~~measure~~market participation potential for the program.

~~(2)~~(5) Projections of program costs and the basis for ~~costs;~~those projections.

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~~(3)~~(6) Projections of ~~measure~~ peak load (kW) and annual energy (kWh) ~~impacts and associated avoided costs~~effect, reflecting the percentage of measures that would have implemented without the program, and the extent to which non-participants implement additional measures due to the program;

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~~(4) Assumption regarding each measure's useful life;~~

(7) Estimates of the effective useful lives ("EUL") of the measures that would be installed under the program. Such estimates, in general, should reflect the lifetime assumptions that have been validated, and are in wide use, in jurisdictions with comprehensive efficiency programs. Utilities shall identify the origin of all EUL values utilized.

Estimates of

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~~(5) Projections and forecast of market potential;~~

~~(6) Current saturation of the measure;~~

~~(7)~~(8) ~~Assumptions on~~ participant benefits, if any, other than electricity savings~~; and~~ (e.g., gas savings, water savings, reduced operating and maintenance costs, deferring future equipment replacements).

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vi) The IRP shall include demand-side screening using the following methods.

~~(8)~~ The principal screening test for measures and programs is the Total Resource Cost ("TRC") test, which measures the net benefit of a demand-side management program as the difference between the total costs and benefits of the program, including both the participants' and the utility's costs. The *benefits* calculated in the TRC test are the avoided supply costs, including all the cost reductions identified in Section 2)b), plus any non-electrical benefits to participants. The *costs* in this test are the program costs paid by the utility and the participants plus any increases in supply costs (e.g., due to increased off-peak usage) and participant costs, net of any tax credits. Thus all equipment costs, installation, operation and maintenance, cost of removal (less salvage value), and administration costs, no matter who pays for them, are included in this test. ~~Any other information deemed pertinent by the utility.~~

~~ii) Demand Side Screening. All of the Screening Tests defined in the Definition Section above (Section 2) should be performed. This includes the Participants Test, the rate impact measure test ("RIM Test"), the utility cost test, and the total resource cost test ("TRC). Measures that fail the screening test should be eliminated from further consideration in the IRP. The utility's demand side screening process should be fully described in the IRP Report. All demand side measures eliminated as a result of the utility's screening process should be discussed in the IRP Report, and the reason for the measure's elimination should be explained. Other screening approaches may be used; however, the utility should provide an explanation of its rationale for using such an alternative approach.~~

(1) The TRC determines whether the program or measure is cost-effective.

(2) The secondary DSM screening test is the Utility Cost Test, which measures the net effect on costs that flow through the utility. The benefits are the avoided supply costs. The costs are those incurred by the utility, including the incentives paid to participants, any increase in supply costs, initial and continuing program implementation and administrative costs. For load-management programs, costs may also include utility control and communication equipment and installation, operation and maintenance, and costs due to customer dropout and removal of equipment (less salvage value). The Utility Cost Test determines whether the costs to the utility system exceed the benefits to the system.

(3) The utility should endeavor to procure all efficiency savings that pass the TRC test (benefits minus costs are greater than zero).

(a) If a proposed program passes the TRC test but fails the Utility Cost Test, the utility shall review the incentives in the program and attempt to raise the Utility Cost Test to a positive number. The IRP Report should discuss any conflicts between the TRC and Utility Cost Test.

(b) If a proposed program fails the TRC, the utility should determine the reason for such failure, and improve the program by removing non-cost-effective measures, adding measures or improving incentives to increase benefits and cover fixed costs, or otherwise redesign the program to provide cost-effective efficiency services to the targeted market segment. If the utility cannot design a cost-effective program for the market segment, the IRP Report should explain the nature of the problem and the utility's attempts to correct it.

(c) If the utility proposes to pursue a program that does not pass the TRC (e.g., for low-income customers), the IRP Report should explain why the program is not cost-effective and why the utility has chosen to pursue the program.

(4) Programs shall be screened including all benefits and the incremental costs of adding the program to the portfolio. For programs that would offer a discrete set of measures (as opposed to custom implementation), measures should be screened including all benefits and the incremental costs of adding the measure to the program.

vii) The IRP projection of energy-efficiency programs shall include developments beyond current conditions, reflecting continuing improvement in end-use technology and program design, offset by the rise in standard practice and efficiency standards reflected in the utility's load forecast.

viii) The IRP Report shall include a comparison of the projected energy-efficiency results to goals and achievements of leading utilities and other program administrators, considering the utility's current and future experience with energy-efficiency programs. If the IRP Report does not project results comparable to those of the utilities and program administrators with the largest savings, the Report shall explain why.

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~~iii) Program Design – All demand side measures which pass the screening test should be incorporated into one or more demand side program, taking into account the program administrative costs and interactions between measures. Additional program screening should be performed and consideration should be given to re design programs if possible to make the programs more cost effective. Any programs that pass the final screening test should be further evaluated by the utility for consideration to become either full scale programs or pilot programs. The utility's demand side program design process should be fully described in the IRP Report.~~

d) Supply-side Options

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i) A range of supply-side resources (both generation technologies and capacity purchases) ~~should~~shall be evaluated. The utility ~~should~~shall compile a list of resources that are ~~potentially~~likely to be feasible, including both renewable and non-renewable options~~.~~, and both utility ownership and purchase from IPPs and merchant plants. For each supply-side option on this list, the utility should include in its IRP Report a description of the option, including at least the following information:

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(1) Resource type~~;~~, including

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~~(2) Capacity;~~

~~(3) Fuel Type;~~

~~(4) Ownership information;~~

(a) whether the resource is specific (a purchase from an existing resource, construction of a particular unit at a particular location, life-extension or repowering of a particular unit) or generic

(b) unit type (e.g., boiler, combustion turbine, combined-cycle; sub-critical, super-critical, fluidized bed, IGCC) and ;

(2) Unit and plant capacity, nominal and summer firm;

(3) Fuel type and heat rate, if applicable;

(4) Potential or actual ownership information (e.g., wholly owned by the utility, jointly owned, third party ownership);

(5) Location and effect on transmission adequacy;

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(6) Anticipated life~~;~~;

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~~(7) A description of the measure;~~

(7) Availability;

(8) Operating costs, including O&M, property taxes and capital additions;

(9) Operational characteristics, including dispatchability, ramp rates, start-up time, minimum load level, minimum up time, and minimum down time.

~~(8)~~(10) Capital ~~Cost~~cost and AFUDC ~~assumption~~estimates, if applicable;

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(11) Probable environmental costs associated with continuing operation during the planning period.

~~(9)~~(12) Any other information deemed pertinent by the utility.

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ii) Supply-Side Screening. ~~Supply side options should be screened in order to reduce the~~If a large number of potential ~~options for further consideration. The recommended screening~~ supply alternatives are identified, the utility shall select a manageable number of the most promising options. One approach for screening supply-side options is to compare the levelized ~~or present value of~~ revenue requirements over the life of the resource at varying ~~levels of operation or~~ capacity ~~factor. Typically, supply side resource screening curves are developed and certain~~factors. Some resources ~~can be eliminated based on the screening curve evaluation. The utility's~~ may be dominated by alternatives at all capacity factors and thus be unlikely to be preferred resources. However, considerations other than levelized cost per MWh may be important in supply planning, including dispatchability, load-following, and other measures of operational flexibility. The supply-side screening process ~~should~~shall be fully described in the IRP Report. If the utility eliminates any supply-side ~~measures~~ resources based on its screening analysis, each such ~~measure should~~resource shall be ~~discussed~~described in the IRP Report and the reason for elimination ~~should~~shall be explained. ~~Other screening approaches may be used; however, the utility should provide an explanation of its rationale for using such an alternative approach.~~

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e) A ten year transmission plan shall be provided containing details of all approved and proposed projects at or above the 115 kV level.

i) For each approved or planned new, upgraded or rebuilt transmission facility, the Report shall include at least the following information:

(1) The nature of the project (e.g., line, substation, or capacitor; new construction, upgrade, replacement, or expansion);

(2) The project location, including expected termination points and length for each new transmission line;

(3) the expected design and operating voltage, capacity (MVA) and in-service date;

(4) The approximate cost of each planned expansion or alteration to the transmission network.

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ii) The report shall identify constrained regions on the transmission system where new firm generation resources or load reductions can support reliability of the transmission grid.

iii) Information should be provided regarding any other transmission planning initiatives the utility is involved with, if any.

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f) Preliminary Optimization Analysis. ~~Normally, a production cost~~ The IRP report shall identify the least-cost resource plan, assuming perfect information regarding future conditions and assuming that the utility's reference projections occur.

i) This Reference Plan shall include all energy-efficiency resources that are expected to be less expensive than the sum of avoided costs (energy, generation capacity, reserves, emissions requirements, marginal line losses, transmission and distribution) under the Total Resource Cost test.

ii) The optimization analysis may rely on, an expansion planning model that ~~has an automatic resource selection feature is used to automate the process to select an optimal resource plan. This type of software has the ability~~automatically selects resources to ~~evaluate a large number of resource alternatives over the planning period and to select the most optimal plan subject to an appropriate~~ minimize costs, given a set of inputs assumptions and operating constraints~~. The~~, such as the system planning reserve margin requirement ~~is one such constraint that must be satisfied, while others will also be addressed depending on the operating requirements of the utility,~~ and any regulatory policies that are in effect at the time the IRP is performed. -If it uses an expansion planning model, the utility shall explain how it has checked to ensure that the specific unit sizes, treatment of end effects, and other model inputs have not resulted in uneconomic choices.

~~e)~~iii) The optimization evaluation ~~should~~shall be fully described in the IRP Report~~, with particular emphasis focused on how supply-side and demand-side resources were evaluated in a consistent manner~~.

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~~f)~~g) ~~Scenario and Sensitivity~~ Risk Analyses - The ~~utility should conduct scenario and sensitivity~~ IRP shall include risk analyses ~~of~~ for major assumptions that might ~~impact~~change the ~~results~~selection of resources in the integrated resource plan, particularly for decisions that would appear in the Action Plan.

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~~i) Scenario Analysis - In the case of scenarios, the utility should consider the impact of various reasonable and relevant future policies together. For example, a high CO2 case may imply that not only should high CO2 costs be considered, but possibly higher gas prices and additional transmission options should be considered that would allow access to lower cost wind resources.~~

~~ii)~~i) Sensitivity Analysis~~—In addition to scenario analysis, sensitivity~~—The IRP shall include analyses ~~should also be performed to determine the risk that a specific~~of the costs of the Reference Plan and alternative resource plans with alternative values of important inputs, to examine the extent to which a each expansion plan might be exposed to unacceptable cost increases under certain conditions. Variables that most likely should be examined include:

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(1) fuel prices

~~(2) the load forecast~~

(2) loads

(3) capital costs for new generation resources

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~~(4) inflation and other financial parameters~~

~~(5)~~(4) probable costs of environmental ~~regulations~~compliance.

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ii) Scenario Analysis—The IRP shall include analyses of the costs of the Reference Plan and alternative resource plans under consistent alternative futures, involving changes of multiple inputs from the reference case. For example, high CO_2 prices may be projected to change coal prices, gas prices, load growth, renewables development, and retirement of existing resources. Some scenarios may justify resource changes not considered in the reference case, such as additional transmission options to allow access to lower-cost wind resources.

iii) Flexibility Analysis—To the extent that the sensitivity and scenarios analyses identify critical inputs that would dramatically change the least-cost resource plan, the IRP shall include an analysis of the flexibility of the alternative resource plans to changing conditions. The flexibility analysis shall estimate the cost of starting the resource plan under one set of assumptions (e.g., low fuel) and then finding in a future year (e.g., five years out) that current and forecast conditions have changed (e.g., to high fuel projections), resulting in changing resource plans from that time forward. The flexibility analysis may also consider the effect on various resource plans of price shocks, consisting of abrupt one- to five-year changes in conditions (e.g., doubled gas price, industry-wide nuclear safety shutdowns, drought affecting cooling-water supply, or large recession-related load reductions).

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The intention of these analyses is to evaluate the ~~assumptions that are significant drivers~~robustness of the ~~results.~~alternative resource plans. The ~~sensitivity and scenario analysis~~ risk analyses should be fully described in the IRP Report.

h) Revenue Requirements—The IRP Report shall include projections of annual and present-value revenue requirements, disaggregated by cost category (e.g., generation capital recovery, transmission capital recovery, fuel, energy-efficiency investments) for each candidate resource plan, for the reference case and each risk analysis.

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~~g)~~i) Final Expansion Plan Selection Process – The ~~next~~ final step in the long-term IRP process is to select the final resource plan based on the optimization analysis, ~~sensitivity~~risk analysis, and any other analyses the utility deems necessary. Some judgment may be used in order to examine ~~qualitative~~ such factors~~, such~~ as the potential exposure of customers to rate shocks, ~~the need for~~compliance with uncertain alternative ~~resources due to~~ resource mandates and environmental regulations, ~~the impact on~~and the utility's ability to finance the expansion plan~~, etc. Each utility should discuss in its~~. The IRP Report shall discuss the specific methodological approach and decision-making process followed to select the final set of recommended resources ~~that make up its~~in the IRP.

7) Development of the Action Plan

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The final step of the IRP process is to develop an action plan, which creates a link between the ~~Company's preferred~~Company's recommended portfolio and the specific implementation actions that need to be performed during the first five years of the planning period. The action plan should be included in the IRP Report, and at a minimum, should include the following elements:

a) A timetable indicating each important activity or milestone related to any solicitations, permitting process, construction activities, or other important events. This shall apply to potential acquisitions of demand-side and supply-side resources, retirements, life-extension decisions, power-purchase ~~power~~ agreements, or any other ~~capacity~~ resource ~~matters.~~commitments. This information should be provided for any activities that will be underway or planned to take place within the action plan period.

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b) A complete description of ~~the potential events. Included with this information should be a description of the event.~~each activity, including the amount of capacity involved, when the action will be completed, ~~if~~ the involvement of other parties ~~are involved.~~(contractors, suppliers, co-owners), and other relevant details.

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c) ~~The action plan should discuss~~A discussion of any permitting issues or other regulatory actions that are required in order for the resource ~~acquisition~~action to take place.

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d) ~~The action plan should account for~~ A discussion of the environmental impacts ~~and should discuss the~~of each resource action (acquisition, continued operation, retirement) and plans to meet all environmental regulatory requirements.

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e) ~~The action plan should provide any~~Any other information as may be required by the Commission.

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8) Collaborative Process and Stakeholder Comments

a) As stated elsewhere in these rules a collaborative process, as authorized shall provide stakeholders with a reasonable opportunity to provide detailed input into the development and final recommendations of IRPs developed under these rules. A general schedule for such collaborative discussions is outlined in Section (10)

b) In addition to participating in collaborative discussions stakeholders shall also have the opportunity to file written recommendations regarding the specific data assumptions and methods to be used in the IRP, as detailed in section (10).

c) Regardless of whether the utility adopts the recommendations, the utility shall include a section in the IRP Report documenting all of the stakeholder's recommendations and explaining the Company's reasons for accepting or rejecting each recommendation.

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~~8)~~9) Additional Reporting Requirements

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a) In addition to any reporting requirement discussed in any of the preceding sections, the IRP Report shall include a description of the models ~~used~~ and all modeling methodologies ~~should be included in the IRP Report. While~~used, along with the ~~utility may choose which computer models it prefers to use. the~~utility's reasons for choosing ~~the~~those models ~~should be included in this discussion~~and methodologies.

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~~b)~~ A discussion of any key data assumptions and judgments used in the IRP process not otherwise presented, and an explanation of how those assumptions and judgments were incorporated ~~into the analyses should be included~~ in the IRP Report. Data assumptions that should be reported ~~about~~, in addition to those specified in preceding sections, include~~:~~

~~i) Fuel costs~~

~~ii) Existing generating unit and transaction characteristics~~

such financial

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~~iii) Load forecast~~

~~iv) Transmission topology~~

~~v) QF/Merchant considerations~~

~~vi) Renewable Resource considerations~~

~~vii) Environmental issues~~

~~viii)~~b) ~~Financial~~ information~~, including~~ as the following:

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~~(1)~~i) The general rate of inflation;

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~~(2)~~ii) The AFUDC rates used in the plan;

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~~(3)~~iii) The cost of capital rates ~~used in the plan~~ (debt, equity, and weighted) and the assumed capital structure;

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~~(4)~~iv) The discount rates used ~~in the calculations~~ to determine present worth;

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~~(5)~~v) ~~The tax~~Tax rates ~~used in the plan~~;

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c) ~~If any retirement analyses were performed, the utility should~~The IRP Report shall include full documentation of all analyses leading to recommendations to retire, life-extend or otherwise make major investments in existing generation units. The documentation shall include a complete description of all assumptions, models and results determined from the retirement analysis;

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~~d) For the final IRP plan and each sensitivity alternative, annual revenue requirements should be separately reported by cost categories and the present value of each cost category should be reported;~~

~~e)~~d) All IRP Report filings should include both a public and a confidential version of the Report, as the utility deems appropriate.

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~~9)~~10) IRP Schedule

a) Within thirty (~~60~~30) days of the Commission's issuance of an order in this present docket, each jurisdictional electric utility shall be required to file a simplified IRP Summary Report ("IPSR") that describes its most recently developed long-range resource plan based on whatever resource planning process the utility currently relies on. The Commission does not anticipate that any additional studies will have to be performed to develop this long-range resource plan, as resource planning is already performed on an on-going basis, and it is expected that utilities have already developed such resource plans. ~~The information that should be included in this~~This initial IRP Summary Report ~~is~~shall include:

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i) a description of the load forecast and forecasting methodology;

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ii) a summary of existing resources and transactions;

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iii) a description of key input data assumptions;

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iv) an explanation of the method that had been used to develop the long-range resource plan, including discussion of the modeling tools that had been used and the studies that had been performed to arrive at the resulting long-range resource plan; and

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v) a summary of the key results, including the resulting long-range expansion plan.

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b) Staff will review each utility's ~~IRP~~initial simplified IPSR Report to ensure ~~they contain~~it contains the ~~requested~~required information. Should Staff ~~determine there is anything lacking~~identify omissions, it will inform the utility. Once the utility addresses the ~~deficiency~~deficiencies, the first filing will be deemed complete ~~and no further action~~the Commission will ~~be required~~establish a schedule for comments on the simplified IRP Report. The initial IRP Summary Report and comments will remain on file with the Commission for future reference. The Commission will not hold hearings or issue decisions on the initial IPSR Reports.

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~~b)~~ After each utility files its first ~~IRP~~IPSR Report, it will follow the schedule below to start the next IRP cycle.

[9] The second, and each successive IRP cycle, will begin by the utility filing with the Commission Secretary a Request to Initiate an IRP Process.

i) The Entergy companies (Entergy Louisiana and Entergy Gulf States Louisiana) shall file on the first business day of January of every even-numbered year.
ii) SWEPCo shall file on the first business day of July of every even-numbered year.
iii) CLECo shall file on the first business day of January of every odd-numbered year.
iv) Each co-operative, either individually or jointly, shall file on the first business day of July of every odd-numbered year.

Each filing shall contain a schedule in accordance with the below table for completing its IRP process. Along with the timeline, the utility shall file data assumptions to be used in the IRP and a description of the studies to be performed. The schedule shall also be published on an IRP website that the utility maintains for communicating information regarding its IRP process. Each successive IRP process will be performed based on a ~~3-year~~biennial cycle with the utility filing its IRP report at the end of the ~~3-year~~biennial period.

c) Each IRP Process, as contemplated by this section will be docketed as a Staff-level proceeding that will only be assigned an administrative law judge in the event of a discovery or procedural dispute, or if so ordered by the Commission.

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d) The following table provides the relative schedules ~~that should~~to be followed for the IRP process.

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[9] These dates may be adjusted to coordinate with filing requirements in other jurisdictions.

Schedule of Events

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Event	Description	~~2nd~~Number of Months from IRP ~~Cycle~~Filing Date	~~Each Successive IRP Cycle~~
1	Utility files data assumptions to be used in the IRP (along with a non-disclosure agreement for any confidential data) and a description of studies to be performed	1	
2	First Stakeholder Meeting	~~Number of Months~~ 2	
3	Stakeholders may file written data requests	~~(Months specified are relative to IRP Cycle Start Date)~~2.5	
4	Utility responds to written data requests	3	
~~1~~	~~Utility files non-confidential data assumptions to be used in the IRP and a description of studies to be performed~~Second Stakeholder Meeting	~~1~~4	~~15~~
5	Stakeholders may file written comments	4	
~~2~~6	Draft IRP report published ~~Utility holds first Stakeholder Meeting~~	~~2~~9	~~17~~
7	Third Stakeholders Meeting	10	
~~3~~8	Stakeholders may file written ~~comments~~data requests	~~4~~10.5	~~19~~
9	Utility responds to written data requests	11	
~~4~~	Fourth Stakeholder Meeting~~Draft IRP report published~~	~~11~~12	~~27~~
10	Stakeholders may file comments about draft ~~IRP~~ Report	12	
~~5~~11	Staff files comments about draft IRP Report~~Utility holds second Stakeholders Meeting~~	~~12~~13	~~28~~
12	Final IRP Report filed by the utility	14	
~~6~~13	Stakeholders may file ~~comments about draft IRP Report~~written data requests	~~13~~14.5	~~29~~
14	Utility responds to written data requests	15	
~~7~~15	Stakeholders submit list of disputed issues and alternative recommendations~~Staff files comments about draft IRP Report~~	~~14~~16	~~30~~
16	Staff submits recommendation to the Commission including whether or not a proceeding is necessary for the resolution of disputed issues	17	
~~8~~17	Commission Order acknowledging the IRP or setting disputed issues for hearing ~~Final IRP Report filed by the utility~~	~~15~~18	~~33~~

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~~9~~	~~Staff submits recommendation to the Commission including whether or not a proceeding is necessary for the resolution of disputed issues~~	~~17~~	~~35~~
-	-	-	-
~~10~~	~~Commission Order acknowledging the IRP or setting disputed issues for hearing~~	~~18~~	~~38~~

i) ~~Event 1 – Two stakeholder meetings will be held during the IRP cycle. Prior to the first, and subject~~Event 1—Subject to appropriate confidentiality safeguards, the utility shall publish the data assumptions and a description of studies it intends to perform as part of the IRP process. This will allow Stakeholders the opportunity to review that information and prepare for ~~its meeting~~meetings with the Company.

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ii) Event 2—— At least four collaborative stakeholder meetings will be held during the IRP cycle. Stakeholders will meet with the utility to discuss the initial data ~~assumptions~~inputs for the base and ~~the~~ sensitivity cases~~.~~, as well as the utility's proposed analytical process. This will allow stakeholders the opportunity to ~~provide input~~collaborate in the development of the IRP by suggesting alternative ~~data~~ assumptions and ~~sensitivity cases for~~approaches and bringing additional information to the utility's attention. In addition to scheduled collaborative meetings, the utility ~~to consider.~~ is encouraged to collaborate with stakeholders informally throughout the IRP process.

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iii) ~~Event~~Events 3 -& 4— Stakeholders shall have the opportunity to submit written questions approximately two weeks after the first IRP meeting and receive responses approximately two weeks prior to the first written recommendations.

iv) Event 5—Stakeholders shall have the opportunity to file written recommendations ~~calling for~~regarding the ~~use of~~ specific data assumptions and ~~sensitivity cases by~~methods to be used in the ~~utility.~~ IRP.

~~iii)~~ Event 6—The utility will ~~be required to consider the recommended data assumptions and sensitivity cases, but the utility will not have an obligation to adopt them. Regardless of whether the utility adopts them, the utility will be required to include a section in the IRP Report documenting all of the stakeholder's recommendations, and explaining the Company's reasons for accepting or rejecting each recommendation. This is intended to be a collaborative process that will provide valuable insight as to all stakeholders concerns regarding the utility's IRP.~~

~~iv)~~v) ~~Event 4 The utility will next~~ conduct its initial IRP analysis and ~~will~~ write its IRP Report. The deadline associated with this event ~~refers to when~~is the date utility shall publish its Draft IRP Report.

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~~v)~~vi) Event ~~5~~—7—Stakeholders shall have the opportunity to meet with the utility to discuss the Draft IRP Report.

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~~vi)~~vii) ~~Event 6 and 7~~—Events 8–11—Stakeholders and Staff shall have the opportunity to review the Company's Draft IRP Report and file comments. Staff's review is primarily intended to determine whether the utility met the requirements established in these IRP rules. However, Staff shall not be limited by ~~this~~the requirements and may provide additional comments if it deems it appropriate to do so. Staff may also take the Stakeholders comments into consideration as it develops its own comments.

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~~vii)~~viii) ~~Event 8 This event refers to the date when the utility will publish the Final IRP Report.~~ Event 12—The Final IRP Report will reflect any changes that the utility makes in response to recommendations in Staff's and Stakeholders comments. The utility will be free to implement any changes to its IRP process that it chooses to, as recommended by Staff or the Stakeholders; however, the utility will be under no obligation to do so. Regardless of whether the utility chooses to implement any changes, the utility will be required to include a section in the Final IRP Report documenting all of Staff's and the Stakeholder's recommendations, and explaining the Company's reasons for accepting or rejecting each recommendation. Any changes to the Draft IRP Report made in response to ~~stakeholder~~Stakeholder or Staff's comments, or any other changes made by the utility to the Draft IRP Report, should be clearly identified in some manner such as by providing a redline version of the Final IRP Report.

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ix) ~~Event 9~~ Events 13 & 14— Stakeholders and Staff request any additional information they need to formulate their recommmendations.

~~viii)~~x) Events 15 & 16—Stakeholders will identify any areas in which they disagree with the Final IRP Report. Staff will either recommend that the Commission acknowledge the IRP filed by the utility, or recommend a resolution of disputed issues.

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~~ix)~~xi)Event ~~10 The~~17—If the Commission ~~must first determine if~~determines that there ~~are any~~ disputed issues it will need to resolve~~. If~~, it ~~determines there are, then additional time~~ will ~~be added by the Commission based on~~establish a procedural schedule~~ it determines.~~. Once all issues are resolved~~, then~~ by negotiation or Commission order.

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the Commission will ~~continue with this step. These IRP rules do not include a requirement for a Commission approval process. Instead, the Commission will be required to~~be provide an acknowledgement that the utility's IRP process and its IRP Report have fully complied with the requirements of these IRP rules. That acknowledgement will not constitute Commission approval of the IRP conclusion. The Commission may also, at its discretion, provide ~~recommendations~~directives to the utility for improvements to the utility's IRP inputs and process, including the results in the IRP Report. Any such ~~recommendations~~directives may be considered in any future Commission proceedings concerning the resource plans of the utility.

10) Integrated Resource Plan Update

a) The utility may submit an update to its IRP plan prior to the required submission of its next IRP if:

i) It anticipates submitting an application for a certificate to construct or purchase a supply-side or demand-side resource that was not previously included as part of the IRP;

ii) It anticipates the need to release an RFP for a demand-side or supply-side resource, which was not previously included as part of an integrated resource plan;

iii) The basic data used in the formulation of its last IRP requires significant modification that affects the choice of a resource or use of an RFP that was included as part of the integrated resource plan; or

iv) The Commission or utility finds that other conditions warrant amendment of the utility's IRP. The conditions under which such an amendment is sought shall be specifically set forth in the application for amendment.

b) Each utility shall determine which components of the IRP analysis to incorporate in its update~~; however, the filing of an IRP update does not alleviate the utility's obligation to file a new, complete IRP every three years~~, so long as it responds to any issues raised by the Commission.

c) The filing of an IRP update does not replace the utility's obligation to file a new, complete IRP every two years.

11) Amendments to these IRP Rules

These Rules may be amended at any time by the Commission as it deems necessary.

12) References that were relied upon in developing these rules:

a) Georgia State Code - O.C.G.A. § 46-3A-1 – Chapter 3a covers Integrated Resource Planning - (http://www.lexis-nexis.com/hottopics/gacode/default.asp Search for 46-3a)

b) Georgia Public Service Commission Rules – IRP Rules - 515-3-4 (http://rules.sos.state.ga.us/cgi-bin/page.cgi?g=GEORGIA_PUBLIC_SERVICE_COMMISSION%2FGENERAL_RULES%2FINTEGRATED_RESOURCE_PLANNING%2Findex.html&d=1)

c) Utah Public Service Commission Order – Docket No. 90-2035-01 – Report and Order on Standards and Guidelines Concerning an Integrated Resource Plan for PacifiCorp – June 18, 1992. (Available as a word document)

d) Arkansas Resource Planning Guidelines for Electric Utilities – Approved in Docket 06-028-R, January 4, 2007 (http://www.apscservices.info/Rules/resource_plan_guid_for_elec_06-028-R_1-7-07.pdf)

e) Comments of Parties filed in this docket - LPSC Docket R-30021 – November 13, 2007

f) Technical Conference – LPSC Docket R-30021 - May, 12, 2008

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