MINUTES
CLARIFICATION MEETING

Date: December 22, 2015
Time: 1:07pm (AST)
Location: AFI Legal Conference Room,
268 Ave. Muñoz Rivera, World Plaza,
San Juan, Puerto Rico

Puerto Rico Energy Commission

Physical Attendees:

Tania M. Negrón Vélez
Alejandro Figueroa
Vanessa Acarón
José Román
Mariana Hernández

Remote Panelists:

Jeremy Fisher, PhD, Synapse Energy Economics, Inc.
Janine Migden-Ostrander, JD, The Regulatory Assistance Project

Puerto Rico Electric Power Authority

Physical Attendees:

Nitza Vázquez Rodríguez
Gregory Rivera Chico
Efran Paredes
Sonia Miranda
Alvin Román Fernández
Lisandra Pérez Muñoz
Maribel Franco Vélez

Remote Panelist:

Nelson Bacalao, PhD, Siemens

I. Opening

J. Fisher opened the meeting summarizing the purpose and typical elements of an Integrated Resource Plan (IRP):

> An IRP is an open and public process that's meant to guide a utility's process of procurement, decision making and risk analysis. It is designed to find an optimal least cost plan, take into account constraints, including environmental constraints, policy constraints, and operational constraints, over a long period of time. The term least cost is meant here to mean the least cost net-present value of revenue requirements, taken as a present value from the present day to the end of the analysis period. An IRP typically operates on a 20 to 30-year timeframe to capture impacts of capital decisions that are made both in near term and made over time. It's generally recognized that an IRP gets less accurate as it looks further out into the future, but it's meant as both a decision making tool and as an information sharing tool. In the U.S., about thirty states, primarily those with vertically integrated utilities go through some form of integrated planning process and those integrated planning processes can range anywhere from a simple filing from a utility that indicates they've looked at their supply and taken some analyses of risk, all the way up to a fairly complex and in-depth integrated resource planning processes that looks at a range of supply and demand-side, both scenarios and opportunities, and look at opportunities to find a least cost, least risk mechanism of meeting customer demand.
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> The integrated resource planning process is meant to explore the entire system as a whole, on both the demand and the supply side. It is not just an exploration of supply side opportunities but also of mechanisms of meeting demand through demand side reduction mechanisms and other demand mechanisms, and it's meant to examine near term decisions and look at their value over a long term. Typically, across integrated resource planning processes, plans use a variety of optimization tools. Those optimization tools are designed to look at the impact of both near and long term decisions and fill in capacity decisions over time. Other utilities have used Strategist, System Optimizer, Plexos Long Term and other models that are specifically designed to answer the question: what is the next best resource that I can use to fill into my system. IRPs are, finally, designed to look at how robust the system can be under uncertainty, including uncertainty in fuel prices, uncertainty in emissions limitations and environmental restrictions, demand uncertainties, and a variety of other unknowns. In PREPA's case, there are a large number of uncertainties facing the utility and a large number of near term decisions to be made. And that makes this integrated resource planning process a particularly important one in light of PREPA's mission and understanding of what it needs to do in order to reform its fleet.

J. Fisher stated that these purposes, as summarized, would guide the answers that the Commission gives PREPA. J. Fisher paused and invited PREPA to submit any questions as to the summary.

N. Bacalao joined the floor. He explained that he is a consultant from Siemens helping PREPA in the development of the IRP. He stated that there were no questions as to J. Fisher's summary.

II. Clarification Question & Answer – Take-Aways

Question No. 8: Can the Commission clarify what it means by mechanisms of incorporating [demand-side] resources into its plan development? Does the Commission have a specific mechanism in mind?

Yes, PREPA is required to include the energy efficiency assumptions that are detailed in Point 1.b. of the December 4th Order. If there are other demand-side management techniques that PREPA considers to be suitable for incorporation to the plan, PREPA is welcomed to include those too.

While it would in principle make sense to move demand from the night peak to the day peak, when one factors that the expected cost of the renewable generation is $180/MWh and compare it with the variable cost of an efficient combined cycle burning gas at night approximately $60/MWh with a gas price of $8.5/MMBTU and a heat rate of 7,000 BTU/kWh, it is difficult to justify a rate reduction to achieve this movement.

That would not typically be the type of consideration a utility would evaluate when looking for demand shifting measures. Instead, PREPA would look for the customer's cost for shifting demand and for the prices that customer is able to avoid. In this case, if PREPA has a significant evening peak period that some customers might help shave, there might be extraordinarily highly cost-effective mechanisms to avoid that evening peak. Those mechanisms could potentially save PREPA significantly in both capital expenditures and other types of curtailment costs as required.

In general, the expected cost of the renewable energy generation PREPA quotes as $180 dollars per megawatt is assumed to include an amortized capital cost and possibly also a REC cost but does not necessarily reflect a variable cost of generation. Rather, the expected cost of renewable energy generation is an all-in cost of generation associated with a PPA. PREPA is paying that cost at approximately a fixed price; it's not avoidable on a per megawatt hour basis.

If PREPA has a bimodal peak and the evening peak remains problematic because PREPA would still need fossil generation to meet it, PREPA needs evaluate if there are ways that PREPA can find creative solutions around that problem and address that problem and creative solutions in its answer to Point 4.b. of the December 4th Order.

Question No. 9: How was [the 4.5 cents per kWh] derived?

The value of 4.5 cents per kWh for energy efficiency programs is a weighted average cost of energy efficiency programs across the United States. That's found in a Lawrence-Berkley

National Labs Report from April of this year. That report also talks about the cost of energy efficiency programs across different states, were some states are as low cost as two cents per kWh and other states are closer to six cents per kWh. The states do differ by the level of depth of energy efficiency that they procure, the time for which they've actually been procuring these energy efficiency programs and their efficiency and actually evaluating and then procuring energy efficiency once they've engaged in that type of procurement process. However, it does not substantially change by geography.

For the moment, prior to PREPA having better information about demand side management programs, the Commission is asking that 4.5 cents per kWh be used as a placeholder.

How should this cost be considered (e.g., and additional item to be included in operation costs)?

The energy efficiency cost in most integrated resource plans becomes either one or more separate line item cost. In this case, the 4.5 cents per kWh represents a utility cost—the cost for the utility to procure energy efficiency programs that includes the administrative costs and includes the incentives costs. The energy efficiency cost does not include the participant cost. In most circumstances, the participant cost is left out of utility costs because the participants bear those participant costs. So, in this case, the Commission would expect to see something akin to a 4.5 cents per kWh cost multiplied by the number of kWhs procured on an annual basis as a separate line item.

Question No. 10: In Point 1(b) [of the December 4th Order], is the scenario provided for energy efficiency to be applied to all Portfolios or to the recommended Portfolio 3 to evaluate how it would be modified?

In this case, the December 4th Order asks PREPA to evaluate a series of incremental scenarios. Those incremental scenarios should all include energy efficiency because integrating energy efficiency changes all resource decisions for all Portfolios, not just those for Portfolio 3. Those energy efficiency reductions are to be applied to the new build-outs or the replacements or whatever other resource decisions are made in all of the conditions enumerated in Point 5.a. of the December 4th Order. The incremental optimized scenarios should be applied to a review of all [optimized] Portfolios.

Towards the end of the meeting N. Bacalao stated that he understood that Portfolio 1 is not the least cost option because it implies large amounts of curtailment. N. Bacalao was under the notion that Portfolio 1 should not be pursued in detail. However, J. Fisher clarified in the earlier and more complete answer to Question No. 10 (minutes 22:30 thru 50:30 of the meeting), that a least-cost optimization, as enumerated in Point 1.b. of the December 4th Order, should be conducted under the constraints that it is feasible and operationally stable. To the extent that PREPA finds that Portfolio 1 is clearly unfeasible because of costs or operational instability, it should be excluded. J. Migden underlined that, in the end, PREPA needs to comply with the law, justifying the scenarios used and excluded from consideration.

Question No. 11: Is the reduction provided inclusive of the government energy efficiency, or is it on top of this value?

No, the reduction schedule provided does not account for the government energy efficiency. The reductions apply to residential, commercial and industrial customers. PREPA should design scenarios assuming that both the reductions detailed in the table within Point 1.b. of the December 4th Order and the reductions required of the government will be achieved.

There was one point of clarification, from the Commission, in the Order itself on Point 1(b), the very last sentence was confusingly put in place, were it says "[a]lso break down load (peak, energy) by sector and class, including typical and peak day demand." This information about load is decidedly separate from looking at the exact energy efficiency scenarios that are laid out in Point 1.b. of the December 4th Order. That load information is meant to help inform both the demand-response side and the demand side management. J. Fisher emphasized that that load information is separate from the specific requirement of the energy efficiency schedule that's given on the table within Point 1.b.

For the EE reduction stated in the chart on page 3 of the Order, what is the intention for reduction in base load after 2025?

The table within Point 1.b. December 4th Order states that from the year 2025 and thereafter, PREPA should analyze 1.5 percent incremental energy efficiency savings per year. Thus, years 2026, 2027 through the end of the analysis period all have an incremental 1.5 percent energy efficiency additional savings, based on the previous year.

J. Fisher offered to point N. Bacalao to resources that explain "incremental energy efficiency" and its application in other states. Those resources can be found at the following links:

Demand Side Energy Efficiency Technical Support Document from the Environmental Protection Agency

Benchmarking Electric Utility Energy Efficiency Portfolios in the U.S. from the Coalition for Environmentally Responsible Economies

Question No. 12: Is the Commission asking for additional details on how the level of curtailment was identified?

No. The Commission requires that PREPA details how it arrived at the cost of the renewable energy such as those on table 4-2 of the revised IRP. Point 3.a. of the December 4th Order seeks for capital and operational costs. Those costs were included in the renewable energy PPOAs and they should be elaborated separately, as well as an explanation for why REC prices are included in the PPOA prices and how PREPA arrived at the assumed pricing of the RECs of PV and wind. In essence, what are the capital cost assumptions? What are the O&M assumptions that PREPA used? How did PREPA arrive at the REC prices?

In this case, the Commission is looking for information that underlies the total cost. Column 7 of Table 4-2 in the IRP gives a price in dollars per megawatt hour. The text above Table 4-2 says it includes a REC price, but it neither says how REC prices were determined nor gives a capital cost or an expected lifetime. This lack of information prevents the Commission from deriving an expected capital cost for any of the projects that are in Table 4-2. Also, for the projects that are looked at for the future, it is important for the Commission to understand what PREPA's assumptions are of renewable energy procurement costs.

The Commission had understood that the projects that are at the beginning of that table (e.g. 1 through 8) are based on actual contracts and that the remainder are generic in nature. N. Bacalao stated that the future projects are assumed to have similar contract terms as the existing ones. J. Fisher encouraged PREPA to make that explicit in its answer to Point 3.a. of the December 4th Order. PREPA should also specify what are the terms to which PREPA is referring to as "similar terms". For example, are they pro-rated based on existing contract structures? Is that incremental to existing contract structures? Is it based on how would PREPA evaluate whether those PPAs are actually reasonable relative to its expectations of either self built or other mechanisms of procuring renewable energy?

Question No. 13: Is the Commission requesting PREPA to have a significant portion of PREPA's fleet retired by [the year 2020] and replaced by flexible combined cycle units? Or, on the contrary, should PREPA consider its current gas conversion plans that will result in significant curtailment?

The Commission is not specifically directing PREPA to use any particular fleet alternative but to instead find an optimal portfolio given the set of constraints in the December 4th Order. The set of constraints includes meeting a relaxed version of the renewable portfolio standard by the year 2020 and making clear and explicit assumptions about those prices. Therefore, the portfolio must include sufficient renewable generation to satisfy the requirements of the RPS.

If it is PREPA's assessment that meeting the constraints by 2020 requires replacement of components of the fleet in order to meet a least-cost constraint, then that is the requirement of meeting a least-cost portfolio. If there are practical considerations that prevent that from happening, then those practical considerations need to be enumerated explicitly and an alternative shall be found.

Question No. 14: Can the Commission clarify what it means by which "opportunities" for highly cost effective commercial -and industrial- scale programs" it would like examined? Does the Commission have a specific "alternative management option" in mind for the evening peak?

In this case, PREPA is much more intimately based with its customers than the Commission to comment on the opportunities that exist with large commercial and/or industrial customers to enter into demand-response agreements. Once those cost-effective options in the commercial and industrial sectors are exhausted, PREPA should investigate the residential demand-response options. But PREPA knows its customer base best and typically large demand-response programs are oriented first at large industrial and commercial customers, and PREPA *should examine the extent to which PREPA thinks there might be a cohort of customers that have the opportunity to cost-effectively curtail their peak either during the evening peak or the daytime peak. If there are in fact no commercial and no industrial customers who have the opportunity to avoid peak expenditures through curtailment, then demand-response is not an option. However, J. Fisher pointed out that's very unlikely.*

If there are no surplus resources, what kind of incentives for the move should be considered?

Typically, what's considered in looking at demand response is the pricing associated with it and for the customers, the avoided cost associated with that move and for the utility the savings of being able to shave at those peak hours. And so the utility can offer either programs to incentivize customers to move during those peak hours or customers may be able to find those with the utility's help regardless of those programs. But there are mechanisms that can be put forward by either the company or by third parties to help reduce peak demand.

Question No. 15: What is meant by repowering scenarios, does the Commission mean to use supply options in Portfolio 1?

No. In this case, repowering means any suite of changes in PREPA's generating fleet.

The optimality of the plan should be evaluated with respect to what criteria?

Least cost over a net present value basis.

Is build-out to be tested for only one year?

No. Optimized portfolios are tested for each year of the IRP planning horizon, twenty years in PREPA's case.

Can optimality be demonstrated by the options of reliability criteria?

No, optimality should be demonstrated by least cost over net present value. Regardless of whether PREPA develops the portfolios over individual years or a sweep of years to test dispatch, PREPA must evaluate the repowering scenarios for the entire timeframe of the IRP.

How were the different scenarios to be studied developed?

These scenarios are looking to test the cost-effectiveness of some of the largest contracts and plans being developed by PREPA. These scenarios look to test the cost-effectiveness of AES, EcoEléctrica and Aguirre Offshore Gas Port (AOGP).

An IRP is an appropriate time period in which to evaluate impending contract requirements as well as build-out requirements. And in this case, while AES was partially tested in some of the futures, neither EcoEléctrica and the new signed contracts nor AOGP were exclusively tested as being cost-effective or not. J. Fisher clarified that if it's PREPA's assertion that there would be *no difference in fleet build-outs regardless of whether AOGP is built or not, then the scenario ran in the revised IRP does test AOGP. If this is the case, PREPA needs to explicitly explain this assertion in its answer to Point 5.a. of the December 4th Order. If it is not appropriate assumption that there would be the same build-out with or without AOGP, then the IRP does not currently test the cost effectiveness of AOGP.*

N. Bacalao noted that Future 2 did not have AOGP and that EcoEléctrica, by virtue of its fuel contracts, is one of the cheapest in the system, only second to AES, which led to the question of whether it was necessary to evaluate EcoEléctrica's replacement. However, N. Bacalao responded to his own statement, saying that there might be one scenario in which a new highly efficient combined cycle plant may be slightly cheaper than EcoEléctrica.

N. Bacalao said that the updated IRP build-outs are driven not by economics but by MATS compliance. Without AOGP, PREPA would need to replace the Aguirre units very early on. the economics are affected because of the need to burn expensive light fuel oil. That being said, N. Bacalao stated that when PREPA combines the energy efficiency incremental reductions of Part 1.b. of the December 4th Order, the scenario without the AOGP may have slightly shifted timeframes. N. Bacalao elaborated that PREPA still expects Future 2 (without AOGP) to have the highest costs of supply. PREPA's concern is that not building AOGP will result in higher supply costs.

J. Fisher clarified that PREPA's answer to Point 5 of the December 4th Order needs to be optimized for the combinations of inclusions or absences of AOGP, AES or Ecoeléctrica included in Point 5.a. of the December 4th Order.

Does the analysis need to be conducted with the reduced demand from DSM, DG, Full RPS, and Demand Response programs provided above?

Yes, it does.

Question 16: [Do the revised scenarios] refer to the new scenarios of plant build-out with the reduced demand [from] DSM, EE, DG, Full RPS, and [Demand-Response] programs provided above?

Yes, and specifically Point 6 of the December 4th Order looks to evaluate whether the transmission requirements envisioned by PREPA today remain the same in light of reduced demand requirements and full RPS build-out.

Does the Commission request PREPA to evaluate the impact of having a larger machine in the north, the F class?

That was not a specific request of the December 4th Order.

N. Bacalao understood that the Commission would like the transmission to be reduced on the given optimized portfolio. In other words, PREPA should evaluate transmission in light of the requirements of having effective demand-response, effective energy efficiency programs and *meeting the renewable portfolio standard. Given those constraints, do PREPA's transmission plans remain the same?*

Question No. 17: Can the Commission clarify that the responses to these items are to be disclosed only to the Commission and will be treated as confidential and not be disclosed outside the Commission?

PREPA should file redacted information for other parties and a full un-redacted filing for the Commission's eyes only. The redacted filing would lack the information that PREPA believes is confidential. That redacted filing should be accompanied with a motion to the Commission requesting that confidentiality be afforded to certain information and specifically laying out the basis for the confidentiality claim(s). The Commission will evaluate those confidentiality claims and rule on them.

M. Hernández added that in that motion it is important that PREPA provides the basis of its claims. If PREPA understands that any particular intervenors should not have access to particular confidential information, PREPA must identify those particular intervenors and state the reasons why those intervenors should not have access to that information.

J. Migden elaborated, adding that an example would be competitively sensitive information. However, she emphasized that all the reasons for PREPA's confidentiality claims must be set forth in PREPA's motion, in order for the Commission to fully understand what PREPA's concerns are, review the material and make a ruling.

Question No. 18: The three established interim dates are not achievable due to the magnitude of the work requested, upcoming holidays, and the fact previously mentioned of the required contract amendments.

M. Hernández invited PREPA to file a written request in a form of a motion to reconsider before the Commission on or before December 24th at noon. Nonetheless, even if PREPA files something on or before December 24th at noon, the December 4th Order would still stand and PREPA remains obligated by it.

S. Miranda stated that by December 24th PREPA would send a best estimate of the time required to do the work requested.

Question No. 19: To what extent, if any, are the intervenors expected to provide support for their comments, and to what extent, if any, will PREPA and other intervenors be afforded the opportunity to review and respond?

Intervenors will be given various opportunities to provide comments, etc. in the process, and the Commission will lay out these opportunities in a subsequent order. All the comments the Commission receives, both from intervenors and from PREPA will be considered by the Commission in reaching its ultimate decision in the case. If parties are unhappy with that decision, there will be an opportunity to file an application for re-hearing once the final order comes out. For example, if the Commission bases the decision on something that a party feels *should not have gotten as much weight as it did, that party would have the opportunity to file for re-hearing and put forth why it thinks the Commission relied to much on a particular point of view and should've done something different.*

Do intervenors have the option of submitting comments that indicate that they agree with the relevant portions of the IRP or Siemens' or PREPA's analysis?

Yes, intervenors will have the opportunity to file comments and those comments can be either in support of or critical of PREPA's analyses. There is no limitation that intervenors can only file comments that are critical. Intervenors can also file supporting comments. J. Migden reiterated that the timeline for these opportunities to comment will be set forth at a later date.

The meeting concluded at 3:16pm (AST).