ATTACHMENT D

Methodology, role of STRATEGIST, role of PROMOD® IV, process and sensitivities assessed.

PREPA and its advisors followed a methodology that included a capacity expansion model and a detailed PROMOD® IV model that together with expert opinions and sensitivities resulted in a least cost plan subject to the real constraints that PREPA faces.

When we submitted the Base IRP, it was for us evident that the plan proposed was the least cost option that meets the constraints of environmental compliance (MATS) and capital availability, while facilitating renewable integration and replacing of PREPA's aging generating fleet.

We worked under extreme time pressures and perhaps we should have been clearer at the time on how the information of the First Stage IRP was incorporated in the process and we would have if we were informed that this would be a major requirement for the approval of the IRP.

Nevertheless we wish to correct this omission by describing the process followed below.

<u>Use of a Capacity Expansion Model</u>

The IRP as presented by PREPA to the Commission was based on the results and findings of the First Stage IRP that was developed using STRATEGIST a Capacity Expansion model.

This First Stage IRP provided valuable starting information for the study including:

a) The economic convenience of replacing the entirety of PREPA's base fleet (basically the large steam turbine generation at Aguirre and Costa Sur) as soon as practicable.
    - The base plan replaced these units by 2018 and even an staged plan replaced the units by 2020

b) The convenience of using large combined cycle units (H Class) for the replacement of the generating fleet complemented by reciprocating engines identified.
    - The Base Optimal plan included 7 H Class Combined Cycle Units + 24x18MW reciprocating engines.

c) The level of reserve required that would result in meeting PREPA's reliability standard as discussed next and that was used by PREPA in selecting the amounts of new capacity.

Loss of Load Hours and Planning Reserve Margins.

PREPA's reliability standard of 4 LOLH relates directly with the level of service that it is expected to be provided. It is analogous to the Loss of Load Expectation (LOLE) used by ISO in the continental US. The reliability standards are developed overtime by utilities performing for example studies where cost versus performance is balanced and by observing the application of the principles in practice. The Planning Reserve Margin (PRM) on the other hand is a result of the levels of excess capacity that need to be maintained to provide the target quality of service (LOLH or LOLE). It is a function of i) the size of the largest units with respect of the system peak (the larger the unit the larger the reserve required), ii) the availability of the existing units (the lower the availability the higher the reserve), iii) the load shape (the higher the load factor the flatter the load and the greater exposure results in higher reserve margins) and iv) interconnection with other utilities to share reserves.

It is customary, once this reserve value is determined to use it in the short term and update it periodically. For instance the Mid Continent ISO (MISO) performs a LOLE study annually and uses it to set the minimum PRM for the upcoming planning year and provide a nine (9) year PRM forecast.

Thus we observe that if a large system like the MISO with a peak load of over 129 GW performs yearly updates on its Planning Reserve Margin, it stand to reason that for an IRP that was expected to radically change the composition of the generating fleet, we could not use a predetermined PRM but needed to develop one. We elaborate on this next.

An examination of Puerto Rico generating fleet appears to indicate that there are extremely high reserve levels. However a closer examination shows that many of these units are very old and inefficient (the 21 MW GTs and the Cambalache Units) and/or are will be retired due to condition and environmental compliance (e.g. Palo Seco 1 & 2, San Juan 7&8 and Costa Sur 3&4[1]) . In particular the 70% reserve margin commented by the Commission includes the 21 MW GTs and the Cambalache units, one of which is out of service and whose return is uncertain.

[1] These units while could be designated limited use, they were not considered available for any of IRP evaluations, see Section 3.1 and 7.5 of the " Integrated Resource Plan Volume I: Supply Portfolios and Futures Analysis"

The results of the First Stage IRP allowed PREPA to form an opinion of the reserve margins that would result in the target quality of service once the fleet was modernized and to approximately extrapolate it to the reserve requirements of intermediate steps, where plants with lower availability would be present. To do this we determined a value that we called the "Firm Capacity" calculated by multiplying the capacity of a given plant times its availability and used this to determine a metric that we called the "Firm Reserve"[2]. We did not include in this calculation, however, the Cambalache units or the older 21 MW GT as these units may not be available in the long term and have very low availability[3].

When reviewing the results of the capacity expansion model STRATEGIST for the Base Case with H Class generators we observed that the "firm reserve" was in average 24% or little over twice the size of the largest single unit in the system (the H Class CC). When considering the case with the combination of reciprocating engines and H Class CC the firm reserve was observed to be 28% in average. We also observed that drops in the reserve under 20% resulted in LOLH greater than 4. These reserve values gave us a guide to follow when weighting the multiple considerations we made when selecting the units to put in service and when retiring generation and we adopted a minimum PRM of 23% and a target of 30% firm, which is approximately twice the size of the Aguirre steam units considering a load of 3,000 MW.

Note that it was not always possible to follow this guide, when converting the Aguirre units to burn natural gas and during the repowering of the existing fleet , some years had reduced level of reserve and higher level of LOLH was observed, in particular Portfolio 1 exceeded our target on various occasions and this would have been a concern if we had selected that case.

Again, we realize that we should had been clearer in our description on how we used the results of the Phase 1 IRP and how the capacity expansion model results influenced our decision making. However it must be stressed that this was only one of the factors.

[2] This is analogous to the Unforced Capacity used by some ISO like MISO and PJM, but includes the effect of maintenances as well (see for example https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Training%20Materials/200%20Level%20Training/Level%20200%20-%20Resource%20Adequacy.pdf)

[3] The results of the various portfolios with respect of Firm Capacity and Reserves were presented in the Integrated Resource Plan Volume I: Supply Portfolios and Futures Analysis see sections 8.2.1, 8.2.2 and 8.2.3

Importance of using a PROMOD® IV model.

There are very important aspects that the Capacity Expansion Model simply cannot properly address, but are fundamental in producing a practical plan that is implementable and has the highest chances of success. These aspects include:

a) Inability to properly account for transmission limitations that constraint the amount of generation that can be located at the different sites. In particular for Puerto Rico transmission dictates the need for new generation in the north of the island and places a cap on the maximum generation that can be located in otherwise very convenient places like Costa Sur.
b) Inability to properly model the operating limits of the generating units on a security constrained unit commitment /economic dispatch and this has an important impact on:
    - Capability of the fleet for the integration of renewable generation.
    - Appropriate calculation of fuel and operating costs conditioned among others by dispatch levels the number of starts, which are affected by the integration of renewable.

A model like PROMOD®IV on the other hand allows determining the performance of the various Portfolios considering the key elements of a security constrained unit commitment and economic dispatch, including:

a) Effects of the actual operating capabilities of the generation units; i.e. minimum and maximum capacity levels, ramp rates, start up times / energy, minimum up times, minimum down times, etc. These considerations are not only important for the correct determination of fuel and O&M costs and number of starts, but critical for the assessment of the system capability to integrate renewable generation without excessive curtailment.
b) Transmission limitations down to the nodal level, as without these limitations the cheaper generation can deviate from real dispatch and the impacts of generation location are not properly represented.
c) Proper assessment of emissions as a function of dispatch levels conditioned by the security constrained economic dispatch.
d) Calculation of locational marginal prices and identification of congestion elements in the system that should be addressed.

PROMOD® IV is used for Planning by many ISOs in the US and it allows modeling multiple subsequent years.

<u>The experience of experts is necessary to factor externalities that condition the optimal plan.</u>

In the formulation of the Portfolios for assessment there are practical aspects that are best handled by experts, with the input from computer programs like those obtained from First Stage IRP

These aspects include:

a) Permitting strategy; there are ongoing permits that for successful completion require a number of investments to be done and this conditions the subsequent plans. In particular the conversion to gas of the Aguirre steam units and the combined cycles are integral part of the AOGP permit.

b) Limitations on number of new plants that can be built out simultaneously due to capital constraints, project management, permitting, site construction congestion and reliability of the system as the works will be done at active sites.

c) Limitations on where units are required and where no more units can be installed, which is a complex function of the performance of the transmission system as the system changes over time.

d) Achieving compliance with the RPS without incurring in excessive costs.

e) Achieving MATS compliance in the shortest possible time.

f) Accounting for demand contraction. In Puerto Rico the demand is projected to decline due to i) the historical load reduction that may continue in the future and ii) possible energy efficiency that while it may not be as significant as tested, could reduce the demand further or compensate for future economic development. This case is more challenging than a classical generation expansion case where the timing of new units is driven by the optimal way to attend load growth but one of “capacity contraction” or when to retire generation. In our case the decisions are further complicated given the large amounts of generation being retired at one time (e.g. up to 900 MW at Aguirre or up to 820 MW at Costa Sur) creating a heavily discrete problem. Consider for example that on a typical capacity expansion case, errors in the forecast can result in units being built ahead of its optimal time, while in a "capacity contraction" problem under building will result in either not being able to retire the units, defeating the key objective of the plan, or face quality of service issues.

Portfolio Design.

In developing the Portfolios and its timing PREPA considered the following with respect of generation type, location and number of units

a) Starting from the results of First Stage IRP that recommended the H Class combined cycle and reciprocating engines as part of the solution, via an extensive screening of thermal generation options expanded the candidate technologies to include: (1) intermediate sized combined cycle units the F-Class, (2) small combined cycle units (SCC 800) and (3) simple cycle combustion turbines (GT peakers), in addition to the reciprocating engines.

b) We added the possibility of refurbishing the existing fleet to minimize capital expenditures while improving efficiency, which allow identification of the refurbishing of the Aguirre CC.

c) When selecting the number of units (H Class or F Class) to be considered for the replacement of the large steam units in the Portfolio we considered the size of the generation retired and the resulting impact on reserve with the new units in place so that it would not fall below the selected minimum threshold.

d) When selecting the capacity to be installed in the north we considered the transmission limitations so that this generation together with the new transmission investments, resulted in a secure system.

With respect of other practical considerations for the design of Portfolios, PREPA:

e) Designed strategies that sought compliance with the RPS while balancing the costs of curtailment by timing the increases in renewable generation with the incorporation of flexible combined cycle units that can be turned on and off daily and are still efficient at low generation level.

f) Gave priority to the necessity of achieving MATS compliance in the shortest possible time with the conversion of the Aguirre Units to NG and retirement / designation limited use of the steam turbine generation at San Juan and Palo Seco.

g) Accounted for the AOGP permits limitation including the conversion of the Aguirre steam and combine cycle units to NG and the maximum gas consumption at the site.

h) Accounted for availability of capital as determined by PREPA's current situation and forecasted improvement. This practical and real limitation was a fundamental factor on the timing of the investments. If capital was not an issue the Aguirre 1&2 units and the Costa Sur 5&6 would have been replaced earlier and in line with the findings of the Phase 1 IRP.

<u>Industry practices were used in selecting the alternatives for evaluation.</u>

PREPA and Siemens made a conscious effort to select a variety of "representative" plant configurations and sizes from different manufacturers. We did use real performance data in specific Portfolios, but made sure that reasonably similar performance could be obtained from more than one manufacturer. So the selection of a Portfolio did not lock PREPA into any single manufacturer or plant configuration (1x1 combined cycle for example).

It should be clear that the IRP's recommendation consist of size of the units, the generic technology (combined cycle) and the date/conditions for implementation. The recommendation cannot be more generic than that. The fact that actual performance and cost were used in the assessment only gives PREPA's assurances that the actual plants to be implemented should perform in line with what was modeled.

<u>Range of fuel prices, customer load and capital availability .</u>

PREPA's Base and Supplemental IRP explored a reasonably wide range of assumptions for fuel prices, customer load and capital availability. We recognize that due to time restrictions and the multiple aspects to be factored, we initially did not account for the impacts of all of these variables. However when final submission was made we had reached what we call an unknown but bounded analysis of these uncertainties; i.e. tested performance on high and low materializations of the uncertainties.

For fuel prices, the Supplemental IRP evaluated much lower fuel prices than the Base IRP and current forecasts predict values above those considered[4]. The Base IRP evaluated the impact of high prices and going even higher would only make the decision to replace the existing fleet even more convenient, but as discussed below and in the IRP this was not the determining factor in the selection of timing.

With respect of the demand, the Supplemental IRP evaluated a peak demand that is 21% lower than the Base IRP in 2035[5] due to increased Energy Efficiency (EE) assumptions. While we don't think that the levels of EE modeled are achievable for the reasons discussed elsewhere in this document, we see the demand evaluated in the supplemental IRP as representative of a combination of EE and continued attrition of the Puerto Rico economy.

For the definition of its expected future capital availability PREPA worked with its financial advisors to determine an adequate range on assumptions with respect of availability of capital. This practical and real limitation was fundamental for the timing of the investments. If capital was not an issue the Aguirre 1&2 units and the Costa Sur 5&6 would have been replaced earlier and in line with the findings of the First Stage IRP and the results of the Base and Supplemental IRP.

All scenarios started from PREPA's current situation and considered credible levels of improvement of PREPA financial situation, allowing it to either finance directly the investments or be an effective counterpart of in a Power Purchase and Operating Agreement (PPOA). The base scenario (Future 1) assumed slower recovery and provided in the short term the capital required for the investments for MATS compliance; over time PREPA was able to either build

[4] The EIA expects that the WTI will reach the $ 58/barrel by the fourth quarter of 2017, with clear upwards pressure; see https://www.eia.gov/forecasts/steo/report/prices.cfm., while our low forecast had prices under $ 50 and declining.

[5] See table 3-1 in Supplemental IRP

generating units by itself or via a PPOA. The optimistic scenario (Future 3) assumed greater capital flows and the investments in replacement of the large steam turbine units occurred much earlier.

Note that further capital increases would not have accelerated the process significantly due to timing restriction and would only result in a better outcome for the selected portfolio.

A wide range of sensitivities was made to assess the portfolio performance..

A fundamental goal in the formulation of the IRP is identifying a robust plan and identifying options to adapt to adverse future outcomes, once the plan is implemented.

The recommended Portfolio represents a feasible and economic solution based on the criteria and risks known at the time of the IRP. Because the Portfolios would be implemented over several years, they provided PREPA not only a base case plan but also flexibility to modify the type and amount of generation additions later in the plan period as available solutions change, e.g., availability of storage at lower costs than today's. The plan also identifies the critical, near-term projects that must proceed in order to meet short term reliability and environmental compliance goals.

To identify this plan PREPA IRP evaluated a wide range of sensitivities in the Base and Supplemental IRP.

On the Base IRP filed in August 2015, the following sensitivities were included:

a) Full RPS Compliance Sensitivity
b) Renewables Freeze at Current Contracts Sensitivity
c) No AES contract Renewal Sensitivity
d) Access to Capital (Future 3 vs. other Futures)
e) Gas Uncertainty (Future 1 and 4 with AOGP; Future 3 with AOGP and gas to the north; Future 2 with neither AOGP nor gas to the north)
f) Demand levels (Future 4 vs. other Futures)
g) Simple cycle vs. combined cycle vs. reciprocating engines in the north

The Supplemental IRP filed in April 2016 included these additional sensitivities:

h) Lower demand due to Demand Side Management (DSM) Energy Efficiency (EE)
i) Fuel Price Sensitivity
j) NO AOGP
k) No AES
l) No AOGP and No AES
m) No AOGP No EcoEléctrica
n) No AOGP, No AES, and No EcoEléctrica
o) Demand Response
p) Combined cycle vs. reciprocating engines in the north

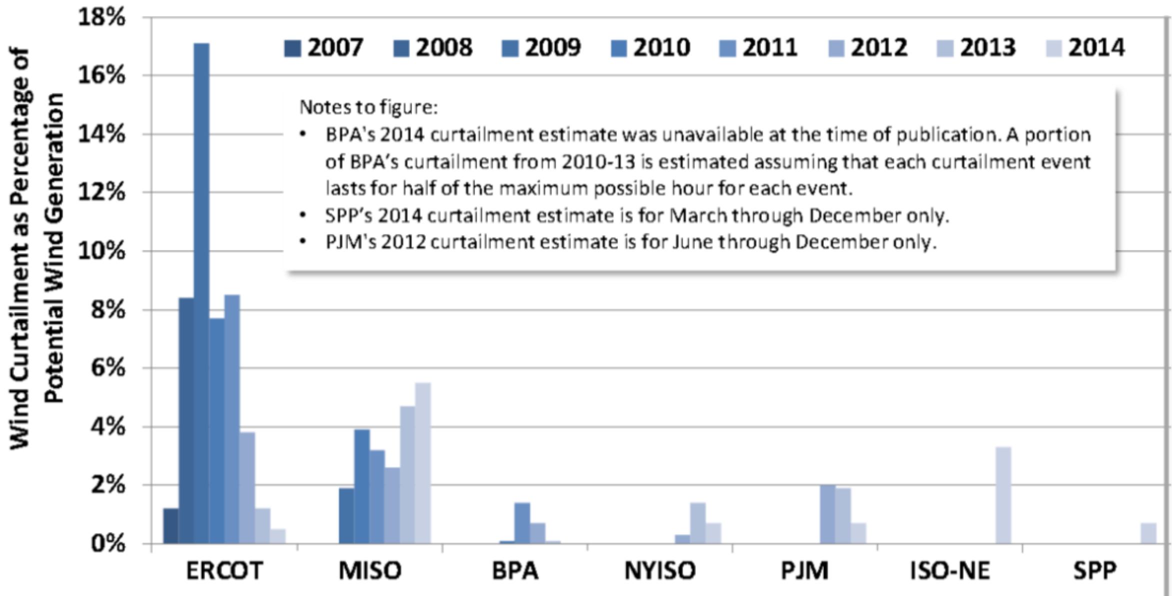
PREPA modeled the renewable prices pragmatically

PREPA when assessing the costs of renewable generation needed to take into consideration the contracts that are valid and enforceable. However as the Commission noted we did provide a sensitivity to the case some of the contracts are rescinded or renegotiated at lower prices. However, it must be clear that at the time the existing contracts were signed the parties were fully aware of the REC's and of its value, thus it stands to reason that this income was considered in addition to the base contractual price as the payments to cover the prudent cost of constructing and operating. Moreover an assessment of the costs of PV that were prevalent at the time the contracts were signed results in a levelized cost of energy in line with the price of the contracts plus the RECs and in particular the levelized cost of energy of $ 130 / MWh to $ 110 /MWh used in the study was calculated to provide prudent return on capital plus cover the operating cost[6] and would be paid by the sum of the REC's and the contractual price.

[6] See section 6.3 of the Supplementary IRP report.

In the formulation of the IRP the 2% was a target, but we accepted deviations to maximize the level of compliance.

PREPA targeted a level of curtailment of 2% in line with the results in the continental US. See for example the figure below that shows an overview of the renewable generation curtailment from 2007 to 2014 and the impact of efforts made to contain it[7].



Source: DOE 2014 Wind Technologies Market Report (August 2015).

In line with the results above and to maximize renewable penetration and the levels of RPS compliance, we accepted higher transient levels of curtailment and never really met the 2% target as can be seen for example in the figure below.

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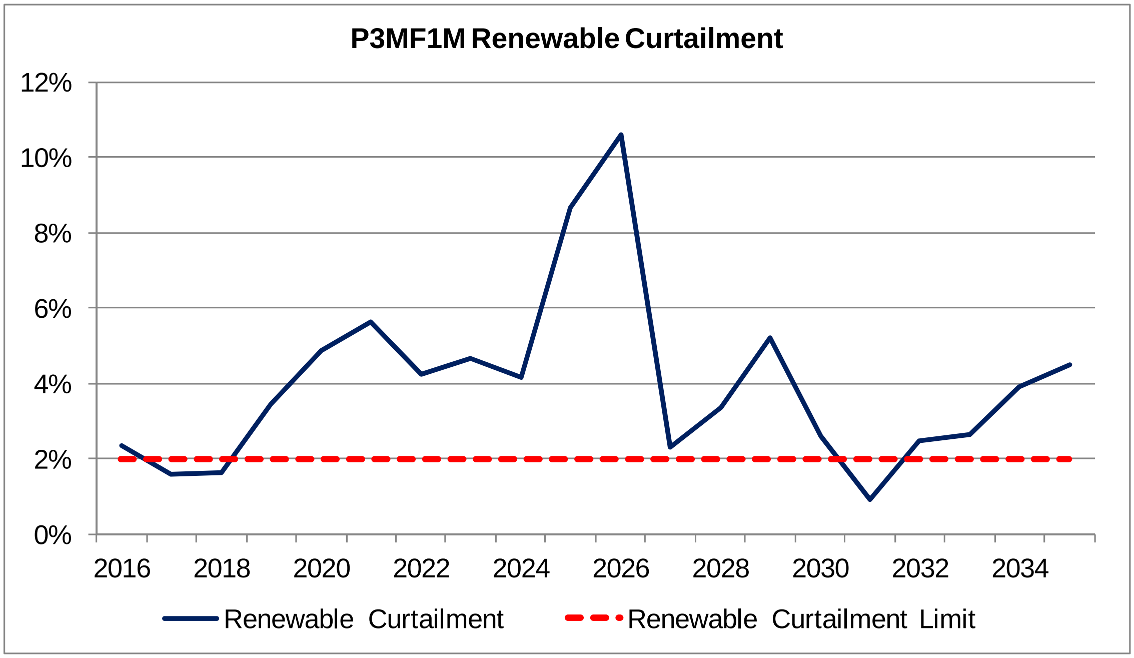
[7] ERCOT has had historically values well in excess of 2% reaching almost 17% in 2009 and this triggered an important transmission expansion, the CREZ system that was completed by the end of 2013. With the CREZ system curtailment is well below 1%. In MISO values are exceeding the 4% level largely due to transmission congestion. The MISO has in place the Multi Value Project (MVP) process that identifies system expansions for which the benefit in congestion relief compensate the associated costs and this has resulted in 17 projects within MISO footprint with an investment of over $ 6.4 billion that will address the uneconomic curtailment.


P3MF1M Renewable Curtailment
12%
10%
8%
6%
4%
2%
0%
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
Renewable Curtailment
Renewable Curtailment Limit