Siemens PTI Report Number: R054-15

Integrated Resource Plan, Addendum I: Losses Considerations

Draft for the Review of the Puerto Rico Energy Commission.

Prepared for

Puerto Rico Electric Power Authority

Submitted by:
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July 15, 2015

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Revision History

Date	Rev.	Description
July 15 2015		Draft for the review of the Puerto Rico Energy Commission.

Contents

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Section
1

Addendum 1

1.1 Introduction

The objective of this Addendum is to provide background information on the consideration and impact of losses in the IRP.

PREPA's losses as a percentage of the gross generation have been in the order of 12.5% to 14.2% as shown the table below. PREPA also historically estimates its technical losses and the balance are attributed to non-technical losses. As can be observed in Table 1-1 the non-technical losses show an increasing trend as the overall demand is reduced. For the demand projection we reversed this trend and maintained the non-technical losses at 5.8%.

For the demand projection we used values for the technical loses in line with PREPA's estimation, also shown below. However, in this addendum, we cover the expected impact that the IRP once implemented is expected to have on the technical loses.

Table 1-1: Technical and Non Technical Losses

	Jul-13	Jan-14	Aug-14	Jan-15	Projection
Transmission Loss	2.9%	2.9%	2.9%	2.9%	2.7%
Distribution losses	5.0%	5.0%	5.0%	5.0%	5.0%
Non Technical Losses	4.6%	5.2%	6.3%	6.0%	5.8%
Total Losses	12.5%	13.1%	14.2%	13.9%	13.5%

1.2 Transmission Technical Losses

1.2.1 Effects on dispatch decisions and Portfolio selection

Although PROMOD®IV can consider the impact of losses in its cost optimization decisions, for the case of Puerto Rico transmission losses have negligible effect on the dispatch. This fact can be appreciated considering that for the most likely Futures where there is only natural gas in the South and not in the North, the cost differential between the generation in the North with respect of the South is in the order of $90 / MWh (estimated based on Portfolio 3 considering the new combined cycles at Aguirre and Palo Seco). Thus considering that the transmission losses are in the order of 3% or less of the delivered power, its cost avoidance can never justify higher generation in the North (closer to the load) at the expense of reducing cheaper generation in the South.

In fact, detailed study of the hourly generation demonstrates that the North-South cost differential drives the dispatch and if it were not for security constraints imposed by the contingency loadings of the transmission system, all the generation would be dispatched in the South irrespective of the losses. In other words, the dispatch is given by the maximum flows acceptable on the transmission system and not by changes in losses.

To gain insight on the effect of losses in the transmission system we modeled, in PSS®E, three system conditions.

Condition 1: corresponds to the short term conditions after the Aguirre CC has been repowered and Aguirre Steam 1&2 has been converted to gas. In the North the smaller combined cycle at Palo Seco has been installed and PSSP and SJSP has been retired or designated limited use.

Condition 2: corresponds to the same condition above but in the long term 2035, when Aguirre 1&2 and Cost Sur 5&6 have been replaced by new efficient combined cycles.

Condition 3: corresponds to a situation where due to gas availability there is more generation installed in the North and the use of transmission is limited. This condition also represents the 2035 situation.

The table below shows the generation sources and location for the three conditions above.

Table 1-2: Evaluated Generation Conditions for Loss Estimation

	Condition	1	2	3
	Year	2022	2035	2035
North	Palo Seco SCC-800 (Duct Fired)	210	210	
	Palo Seco 1x1 F-class			359
	S J Repowering	400	400	400
	San Juan 1x1 F-class or H Class			359
South	Aguirre 1&2	900		
	Costa Sur 5&6	820		
	Aguirre 1&2 CC Unit Gas Repower	263	263	255
	Aguirre 1x 1x1 F-class or H Class		369	359
	Aguirre 2x 1x1 F-class or H Class		738	
	Costa Sur 2x 1x1 F-class or H Class		738	787
	AES & EcoElectrica	961	961	961
	Total North	610	610	1117
	Total South	2944	3070	2361
	Grand Total	3555	3681	3478

We modeled the dispatches from PROMOD corresponding to the peak night and day time peak for the conditions above and estimated the transmission losses. The resulting values are reported in the table below, where we observe that the losses do not vary significantly between night and day time conditions or in the dispatches and this further confirm the little weight that losses have on dispatch decisions.

Table 1-3: Losses Results By Condition

		Condition 1	Condition 2	Condition 3
	Year:	2022	2035	2035
Night Peak	Generation MW	2884.5	2840.8	2852.6
	Load MW	2809.8	2759.9	2782.3
	Losses	2.6%	2.8%	2.5%
Day Peak	Generation MW	2789.1	2666.1	2666.1
	Load MW	2724.7	2605.4	2599.9
	Losses	2.3%	2.3%	2.5%

In conclusion, the implementation of the IRP is expected to be modestly affected by the implementation of the IRP and its materialization does not have an important impact of dispatch or Portfolio decisions.

1.3 Distribution Losses

One possible impact of the IRP is the impact of the distributed generation (DG) on the losses. This impact is direct as DG results of reduction on the end consumption. However, it is expected to be relatively small as shown below.

To estimate the impact of DG we considered that the Power Losses (also known as the peak capacity losses) and those corresponding to the active power losses at the time of the system peak will not be affected by DG, as the system peak occurs during night hours. However, the energy losses can be affected.

The relation between energy and capacity losses can be estimated using the following approximate relationship:

$$\%E_l = (0.3 * LF + 0.7) * \%P_{\ l} = Loss\ Factor * \%P_l$$

Where:

$\%E_l = Energy\ Losses\ in\ \%\ of\ delivered\ energy$

$\%P_l = Power\ Losses\ in\ \%\ of\ delivered\ power$

$LF = Load\ Factor$

So even if the Power Losses are the same, the energy losses will be lower if the load factor is reduced, as will be the case when distributed generation is considered[1]

Based in the formula above the reduction in energy losses can be estimated with the formula below:

[1] The Load Factor is the ratio of the annual energy delivered to the system to the (maximum power delivered x 8760); thus with DG the maximum power stays the same while the energy delivered will be less.

$$\%\, Loss\ Reduction = 1 - \frac{(0.3 * LF_{DG} + 0.7)}{(0.3 * LF_o + 0.7)} = \frac{Loss\ Factor_{DG}}{Loss\ Factor_0}$$

Where:

$LF_{dg} = Load\ Factor\ after\ DG\ is\ considered$

$LF_0 = Load\ Factor\ before\ DG$

To assess the impact, the table below shows for the 20 years of the IRP the Maximum Demand, the energy delivered before and after DG, the corresponding Load Factors and Loss Factors, and the expected reduction in energy losses. As can be observed, DG will result in a reduction of technical losses in the order of 0.7% by the end of the period, which is an added benefit but not a significant driver behind this generation.

Table 1-4: Estimated Loss Impact.

Year	Peak Demand MW	Energy Before DG MWH	Energy after DG MWh	LF Before DG	LF After DG	Loss Factor Before DG	Loss Factor After DG	% Loss Reduction
2015	2980.10	10,063,442	10,011,378	77.10%	76.70%	0.931	0.930	0.1%
2016	2968.60	20,491,553	20,366,285	78.80%	78.32%	0.936	0.935	0.2%
2017	2966.80	20,483,233	20,330,883	78.81%	78.23%	0.936	0.935	0.2%
2018	2964.10	20,463,910	20,286,516	78.81%	78.13%	0.936	0.934	0.2%
2019	2967.70	20,487,828	20,289,399	78.81%	78.05%	0.936	0.934	0.2%
2020	2932.40	20,209,418	19,990,278	78.67%	77.82%	0.936	0.933	0.3%
2021	2919.80	20,119,720	19,879,599	78.66%	77.72%	0.936	0.933	0.3%
2022	2906.80	20,029,972	19,769,267	78.66%	77.64%	0.936	0.933	0.3%
2023	2883.40	19,826,545	19,545,561	78.49%	77.38%	0.935	0.932	0.4%
2024	2860.70	19,624,523	19,323,477	78.31%	77.11%	0.935	0.931	0.4%
2025	2837.00	19,413,712	19,092,995	78.12%	76.83%	0.934	0.930	0.4%
2026	2839.20	19,424,785	19,084,025	78.10%	76.73%	0.934	0.930	0.4%
2027	2841.10	19,435,620	19,074,364	78.09%	76.64%	0.934	0.930	0.5%
2028	2842.80	19,446,200	19,064,331	78.09%	76.55%	0.934	0.930	0.5%
2029	2844.10	19,456,569	19,054,276	78.09%	76.48%	0.934	0.929	0.5%
2030	2845.70	19,466,723	19,044,279	78.09%	76.40%	0.934	0.929	0.5%
2031	2847.10	19,476,666	19,034,097	78.09%	76.32%	0.934	0.929	0.6%
2032	2848.50	19,486,385	19,023,199	78.09%	76.24%	0.934	0.929	0.6%
2033	2849.90	19,495,950	19,011,902	78.09%	76.15%	0.934	0.928	0.6%
2034	2851.30	19,505,290	19,000,683	78.09%	76.07%	0.934	0.928	0.6%
2035	2852.60	19,514,497	18,989,395	78.09%	75.99%	0.934	0.928	0.7%

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