SF RFP PORTFOLIO LOAD CYCLE ANALYSIS

Loading of certain transmission cables serving the South Fork are the some of the critical transmission constraints which the RFP seeks resources to mitigate. Unlike overhead transmission lines, which respond quickly to loading changes, the thermal time constants of underground cables are very long. Therefore, the constraints posed by the cables are not only determined by the peak load, but also by the loss factor defined by the hourly load profile to which the cable is subjected[1]. Deployment of generation, energy storage, and demand reduction resources change the shape of the peak-day hourly load profiles for the areas covered in the South Fork RFP. In general, the deployment of these resources will tend to "flatten" the load profile, thus increasing the loss factor and consequently decrease the peak load limit of the cables.

An analysis has been performed to determine South Fork peak-day hourly load profiles for the years 2022, 2023, and 2030 with application of Portfolios 2, 3, 5, and 6. Portfolio 1 is a transmission option that does not modify the shape of the load profile. Portfolio 4 was not analyzed because its description does not provide sufficient quantitative information on which to base the analysis. These years were selected as the most critical to the transmission planning process. Each analysis was performed for Area 1 alone, and for the combined loading and resources of Areas 2 and 3, as the critical cable loading issues do not require discrimination between Area 2 and Area 3 loads and resources.

Although the initial purpose of this analysis was to determine load profiles for the purpose of cable rating determination, this analysis has revealed results that can inform the evaluation and optimization of the resource portfolios. Of particular note are findings indicating that battery resources may not be able to be fully utilized, even on peak days, due to insufficient duration and depth of load "valleys" in which re-charging may be performed. (High load periods are typically caused by heat waves, and many heat waves are multi-day events where several days in a row achieve daily peaks that are close to the overall peak. Therefore, the analysis assumes the load cycles are recurring.) Another significant finding is that most of the portfolios reduce the peak transmission capability to the South Fork, by virtue of the increased loss factor on underground cable circuits.

LOAD PROFILE MODELING APPROACH AND ASSUMPTIONS

The analyses of the portfolios were performed on an hour-by-hour basis for each study year using the forecast peak-day load profile for each area, deploying the resources such that the peak demand of each area is reduced, thus flattening the load profile. The demand response resources (AEG and NEX) were the initial resources applied in each analysis,

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[1] Loss factor is the mean square of the hourly cable loading in per-unit of the peak load. Loss factor can be related to a load factor, as explained later in this report.

followed by fuel cell, microgrid, wind, battery storage, and lastly, dispatchable fuel-burning resources (combustion turbines, reciprocating engines). The deployments were made with due regard for the characteristics and limitations of each of the resources comprising the portfolio. This is a painstaking, mostly manual process when performed in a spreadsheet with full knowledge of the entire load cycle. This raises the important question of how these resources will be controlled, and how accurate will be that control, in the actual operating environment where future load demand is not known precisely. It is likely that very substantial resources may need to be committed to developing the operating systems required to control these assets, and additional human resources may be required to operate this relatively small portion of the LIPA system.

The assumptions and limitations of each resource type as used in this analysis are as defined below:

AEG-100 (Demand Response)

This demand response is primarily achieved through modification of HVAC system operation, via customer thermostat setpoints and cycling limitations. When air conditioning thermostat setpoints are raised at the start of the four-hour load reduction period, a substantial initial drop in load is assumed to occur, followed by a slow rise with a two-hour thermal time constant (assumed), reaching the guaranteed demand decrease value at the end of the four hour reduction period. When the period concludes, it is assumed that the thermostats will be immediately reset to the comfort level. This will cause a step increase in demand assumed to be equal and opposite to the negative demand step at the start of the load reduction period. This rebound in demand is assumed to decay with a two hour time constant. The parameters of this load modification behavior are such that the rebound energy is approximately 70% of the energy decrease during the reduction period, which is typical for HVAC demand response programs.

Figure 1 plots the assumed change in demand, in per-unit of the guaranteed demand reduction value, as a function of the hour of day. This demand modification profile is admittedly speculative. However, it can be safely concluded that an HVAC demand modification will have a substantial rebound, and this rebound will take place immediately following the end of the demand reduction period. Because of the small magnitude of the AEG proposal, and the fact that other dispatchable resources were used to “fill in” around this assumed profile, the assumptions made for this demand response do not have a significant effect on the profiles.

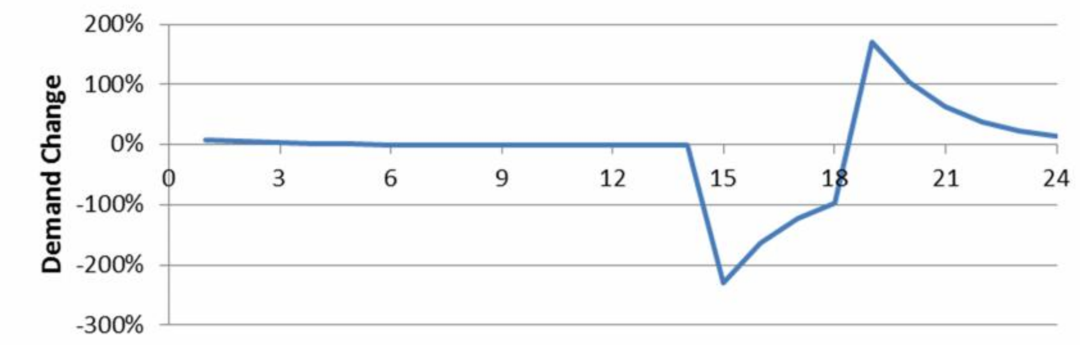

Figure 1 Assumed hourly demand change profile for AEG 100, in percent of guaranteed reduction

Thermal Energy Storage (NEX)

In the portfolios where the NEX thermal energy storage resource was included, this resource was deployed on a flat basis at rated value for the most optimal consecutive four hour period. The rebound, or recharge, was at 57.5% of the rated value over eight early morning hours.

Fuel Cell (FCE)

Due to the characteristics of the fuel cell resource, it was assumed to be flat-loaded to capacity on a 24 hour basis during peak days.

Battery Storage (AES, LIE, GCN)

Both battery energy storage discharge and recharge were assumed to be fully dispatchable to meet the goal of demand reduction. The limitations on charge/discharge rate (MW), and maximum stored energy (MWh) for each battery resource were observed at all times. Additionally, the energy available for discharge into the system was discounted by the stated round-trip losses of the battery resource. The LIE400 33 MW battery was treated as a special case for years 2023 and 2030, paired with the DWW wind resource. This hybrid resource is described separately below.

Offshore Wind + Battery (DWW100 + LIE400)

The DWW100 offshore wind resource, which has a 90 MW installed wind turbine capacity and 75 MW output limitation, was modeled as a hybrid resource in combination with the 33 MW, 264 MWh LIE400 battery. Separate analysis has shown that the hybrid resource can deliver 40 MW block capacity over an eight hour period with a 5% effective forced outage rate (EFOR). For this analysis, it was assumed that the combined resource can deliver a total of 320 MWh of energy as needed over one day's peak load period. There were a few hours in the analysis where the combined resource delivered slightly more than 40 MW.

The EFOR analysis assumed no correlation between high load and persistent low-wind conditions. Initial analysis of temperature/wind correlation in the Block Island data provided by DWW indicates that such a correlation may exist. Therefore, basing the portfolio analysis on an uncorrelated 5% EFOR basis is not believed to be excessively conservative.

Microgrids (ANB)

The ANB microgrid projects were (optimistically) assumed to be fully dispatchable to meet area load-leveling needs with the constraints that the maximum demand change is limited to the rated value, and the total energy of the peak reduction is limited to eight times the microgrid's rating. Based on the composition of the microgrids, an energy rebound of 70% was assumed for the microgrids in Areas 2 and 3, and 60% for Area 1. This rebound was assumed to be dispatchable to the most advantageous hours for area load leveling. The assumptions regarding the microgrids' flexibility are speculative, as these are not clearly defined in the proposals.

Combustion Turbines (HAL) and Reciprocating Engines

In general, these resources were deployed only as necessary to reduce peak demand. An exception is that the HAL turbine in Area 1 was deployed on a 24 hour basis to "recharge the battery" as specified in the portfolio descriptions.

Peak Load Reduction

Table 1 displays the peak load reduction results determined by the portfolio analyses. In many cases, the achievable reduction is significantly less than the total of the resource capabilities of each portfolio. This is due to insufficient time or available energy to accommodate battery recharging, and the reliability constraints assumed for the hybrid wind and storage resource. Figure 2 shows load curves for Profile 3 in 2023 as an example. The significant issues experienced with each portfolio are discussed below.

Table 1
Area Peak Loads and Load Reduction (MW)

	2022		2023		2030	
Portfolio	**Area 1**	**Areas 2+3**	**Area 1**	**Areas 2+3**	**Area 1**	**Areas 2+3**
None	28.1	283.0	28.9	290.6	35.1	353.1
Portfolio 2	18.8 (-9.3)	227.9 (-55.1)	19.6 (-9.3)	225.0 (-65.6)	25.0 (-10.1)	285.8 (-67.3)
Portfolio 3	23.1 (-5.0)	234.7 (-48.3)	24.0 (-4.9)	234.7 (-55.9)	29.4 (-5.7)	296.7 (-56.4)
Portfolio 5	22.1 (-6.0)	235.3 (-47.7)	18.1 (-10.8)	242.1 (-48.5)	23.2 (-11.9)	302.1 (-51.0)
Portfolio 6	22.6 (-5.5)	220.8 (-62.2)	22.6 (-6.3)	228.3 (-62.3)	28.7 (-6.4)	283.7 (-69.4)

WESC

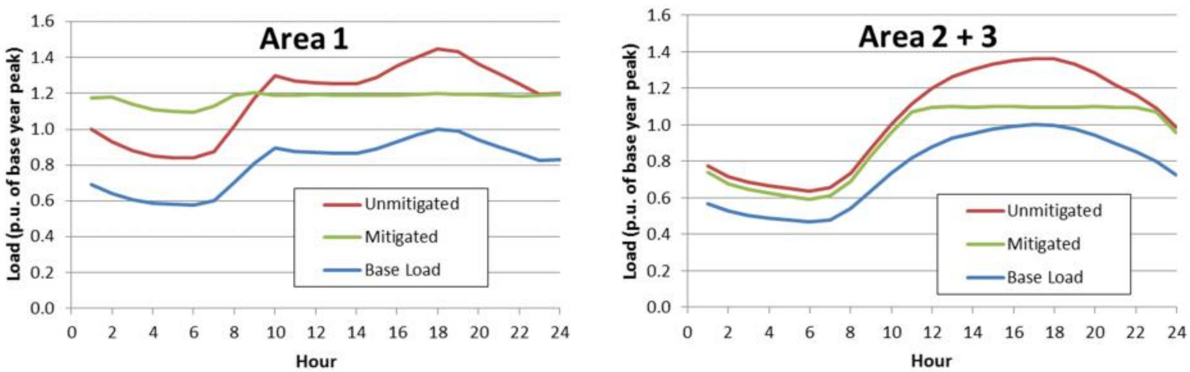

Figure 2 Base load profile, 2023 load profile, and 2023 profile with Portfolio 3 applied

Portfolios 2 and 3

For Area 1, the constraining factors are both the energy capacity of the LIE battery and the amount of time in which it could be recharged at a rate within its power limitation in order to achieve rated energy. For Areas 2+3, except in 2022, the constraining factor is the assumed 240 MWh limit of the DWW + LIE400 hybrid resource. In 2022, the constraining factor for Areas 2+3 is the maximum 33 MW output of the LIE400 battery.

Portfolio 5

The load was flat-lined in Area 1 for only partial deployment of resources requiring recharging or having a rebound characteristic. These resources could not be increased to their rated MW capacities without causing new peaks in the normally off-peak periods. For Areas 2+3, battery energy capacity was the limiting factor to peak load reduction.

Portfolio 6

The limitation to peak load reduction in Area 1 is the power limit of the reciprocating engine generators. In Areas 2+3, the limiting factor was the assumed energy capability of the hybrid wind and storage resources.

LOAD FACTORS AND CABLE RATING IMPACTS

Effective Load Factor

The truly relevant characteristic of a load profile shape to cable ampacity is the loss factor, as mentioned previously. However, the cable ampacity software used by PSEG-LI uses as an input the load factor (average load divided by peak load) as a convenience to the user. An industry rule-of-thumb, that is presumed to be used by the ampacity software to convert load factor (*LdF*) to loss factor (*LsF*), is:

$$LsF = 0.7 \cdot LdF^2 + 0.3 \cdot LdF$$

Because the load reduction portfolios result in highly atypical load profile shapes, it was decided that it would be most accurate to convert the loss factor from the resulting net load curves, and then convert these into effective loss factors using the above relationship. This is expected to provide a more realistic assessment of cable thermal impact than direct application of the actual load factor.

Portfolio Effective Load Factors

Table 2 provides the effective load factors for the portfolios for the study years. The 23 kV transmission cables east of Amangasett are subjected to Area 1 load, and under contingency conditions the entire Area 1 load is carried by one of these cables. The Southold-Buell and Canal-Southampton cables are affected by the total load of Areas 1, 2, and 3. The Riverhead-Canal 138 kV cable loading is affected by the sum of all areas, plus the loading at Canal. Thus the load factors are calculated for the combinations of area loadings as shown.

The portfolios can be seen to substantially increase the load factors, which tend to decrease the peak load capacity of underground transmission lines which serve the respective areas.

Table 2
Effective Load Factors

		Portfolios				
Areas	**Year**	**None**	**2**	**3**	**5**	**6**
Area 1	**2022**	0.786	0.969	0.981	0.990	0.926
	2023	0.786	0.954	0.971	0.997	0.926
	2030	0.786	0.948	0.959	0.996	0.910
Areas 1+2+3	**2022**	0.758	0.866	0.860	0.892	0.870
	2023	0.758	0.855	0.847	0.889	0.867
	2030	0.758	0.840	0.828	0.869	0.859
All + Canal	**2022**	0.750	0.856	0.851	0.882	0.859
	2023	0.750	0.845	0.840	0.876	0.856
	2030	0.750	0.832	0.822	0.861	0.849

Net Load Reduction

At the time this report was drafted, [redacted] Therefore, the impact of the load profiles on transmission capacity into Area 1 during a long-duration can be determined. Table 3 summarizes the impact of the portfolios on both peak load and transmission capacity, with the difference between the reduction in load and decrease in transmission capacity shown as "net improvement".

Defining effectiveness as the amount of net improvement divided by the peak load decrease, the effectiveness values of the portfolios for Area 1 are in the range of 68% to 77%, excluding Portfolio 3. The effectiveness of this portfolio is in the range of 45% to 57%, due to the greater reliance on energy storage and demand response with rebound in this portfolio instead of generation resources.

Analysis of the individual effectiveness of resources in a portfolio is revealing. Such a marginal analysis was performed for Portfolio 2 in 2030. Starting from the no-mitigation load profile, the individual resources were turned on one at a time with the same output/input profile as used to meet the all-resource portfolio dispatch. The AEG demand response resource provides only 37% effectiveness, the LIE battery provides 64% effectiveness, and the HAL combustion turbine provides a 110% effectiveness. The generation resource provided an incremental effectiveness greater than 100% because the change in the load profile decreased the load factor, and thus increased transmission capacity. This effectiveness variation between different types of resources might be considered as part of the economic evaluation of resources.

Similar information for cables feeding Areas 2 and 3 were obtained as this draft was completed and a future update of this report will include analysis of load profile impacts on transmission constraints applying to these areas.

Table 3
Area 1 Net Transmission Loading

		Portfolios				
Year		**None**	**2**	**3**	**5**	**6**
2022	**Peak Load**	28.1	18.8	23.1	22.1	22.6
	Transmission Capacity	23.3	20.7	20.6	20.5	21.3
	Gross Load Reduction		9.3	5.0	6.0	5.5
	Capacity Reduction		2.6	2.7	2.8	2.0
	Net Improvement		6.7	2.3	3.2	3.5
2023	**Peak Load**	28.9	19.6	24.0	18.1	22.6
	Transmission Capacity	23.3	20.9	20.7	20.4	21.3
	Gross Load Reduction		9.3	4.9	10.8	6.3
	Capacity Reduction		2.4	2.6	2.9	2.0
	Net Improvement		6.9	2.3	7.9	4.3
2030	**Peak Load**	35.1	25.0	29.4	23.2	28.7
	Transmission Capacity	23.3	21.0	20.9	20.4	21.5
	Gross Load Reduction		10.1	5.7	11.9	6.4
	Capacity Reduction		2.3	2.4	2.9	1.8
	Net Improvement		7.8	3.3	9.0	4.6