

## REALIZING STACKED BENEFITS OPPORTUNITIES OF A DISTRIBUTION CONNECTED ENERGY STORAGE SYSTEM

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### ABSTRACT

*The Rochester Gas & Electric (“RG&E”), an AVANGRID company, is planning the installation of a Battery Energy Storage systems (BESS) in the Northeastern part of United States. RG&E plans to own and operate a substation-sited BESS and demonstrate distribution system benefits as well as provide improved quality of service. This paper presents results from the analysis that were performed to evaluate the proper sizing of a substation-sited BESS system. Methodologies utilized for evaluating impacts and benefits of storage operations are presented. Results depicting how BESS can provide additional stacked benefits beyond the primary objective of distribution substation transformer deferral, are provided.*

### INTRODUCTION

Traditionally, the distribution system is planned for the lowest cost solution that can meet the changing demand and provide the power supply reliably to the connected loads. In the past few years with the adoption of renewable generation and distributed energy resource (DER) technologies, the distribution system paradigm has been changing. Additionally, energy storage [1],[2] is receiving increasing attention by utility engineers and regulators alike for its potential to solve various technical challenges in the management of the electric system. The distribution planning process now needs to include analysis on the impacts and benefits of incorporating distributed generation and energy storage systems into the distribution system.

BESS is a flexible asset that can be used to improve asset utilization at the distribution level, and it has the potential to be used for a variety of other applications. Stacked-benefit operation adds services that can generate new value streams and improve economic viability of BESS. However, stacked-benefit operation also adds complexity by stacking operational requirements that can potentially conflict with each other.

This paper describes the methodology utilized to evaluate the stacked benefits of BESS. Results are presented using

an actual feeder where a BESS system is planned to be commissioned in 2019.

### PROJECT DESCRIPTION & OBJECTIVES

RG&E is planning the installation of a distribution connected BESS on a 12.5 kV bus at one of their 35/12.5kV substation. RG&E plans to own and operate this BESS to demonstrate the benefits of battery storage. The primary driver for this project is to address a capacity deficiency at a 35/12.5 kV distribution transformer illustrated in Figure 1.

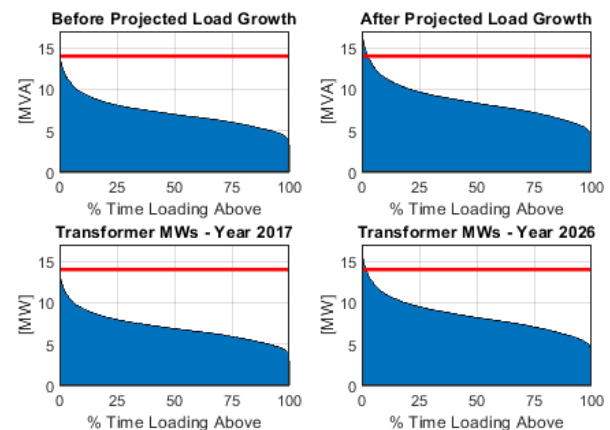


Figure 1. Distribution substation transformer load duration curves before and after projected load growth

Based on actual load forecast, RG&E would plan to initiate standard utility upgrades to accommodate and serve load that is projected in years to come. The transformer peak load is currently at 14 MW and requires an upgrade to meet the projected load growth of 2% per year as shown in Figure 1.

The implementation of a BESS offers the ability for RG&E distribution operations to utilize an alternative “non-wires” solution to mitigate an expected capacity deficiency, manage the system reliability through low load periods, improve power quality and demonstrate the value of additional battery technology capabilities. Peak loads at this station typically occur in the afternoons and low-load conditions occur in early mornings. RG&E can operate the BESS by discharging the battery during high-

load periods and charging of the battery during low-load conditions. Since these high peaks and low load times occur during similar time frames every day, the BESS can operate based on scheduled charging and optimized discharging to reduce manual operation intervention.

This BESS alternative is expected to defer or provide typical utility solutions that include load transfers, equipment upgrades, and construction of a new substation. There is also a high reactive power compensation need for this feeder. It is envisioned that a combination of BESS and feeder capacitors will be able to improve the reactive power needs and maintain the substation power factor to greater than or equal to 0.97 power factor at all times during the year.

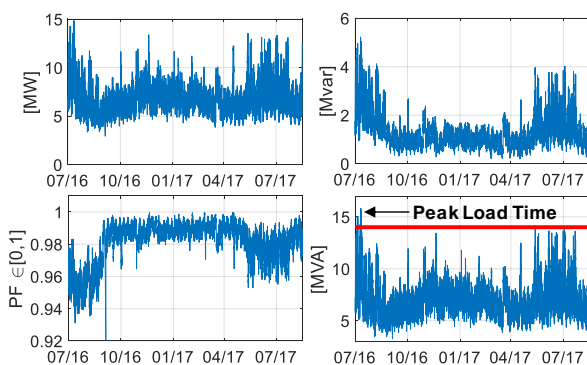


Figure 2. Transformer real and reactive power variations

The key applications for a substation-sited battery storage system that were considered in the analysis include:

- (1) *Peak Load Reduction* – Reduce peak electrical demand to defer otherwise needed distribution system upgrades. Also, maintain power factor at or above 97%.
- (2) *Tap Operation Reduction* – Reduce switching of the transformer Load Tap Changer (“LTC”) to improve operations and maintenance expenses
- (3) *Power Quality* – reducing the occurrence and/or severity of voltage-related power quality issues (e.g., voltage sag) and thus, increase customers service quality
- (4) *Increase system efficiency* – reducing the distribution substation transformers losses by providing reactive compensation with BESS

Although a detailed cost benefit analysis was conducted as part of this study, those results are not presented in this paper.

## DISTRIBUTION SERVICE ANALYSIS

This section shows the energy storage analysis for the distribution services listed above.

### Capacity Deferral & Var Compensation

The primary storage distribution service is to defer the investment for a new transformer with a higher capacity

to address the capacity limitations of the existing transformer. Figure 2 illustrates the substation transformer loading in 2016. The peak load of 15.83 MVA (14.96 MW) occurred in July 2016. The transformer has fairly low power factor during high load times that is likely caused by induction motor loads on a feeder served by the transformer.

Load duration curves provide an intuitive view of the transformer loading. Figure 1 shows the transformer MVA and MW duration curves in 2017 and 2026 calculated with the utility forecast of an annual load growth of 2%. The peak of the MVA duration curve is notably higher due to the low power factor at high load times. In 2017, the transformer loading exceeded the highest manufacturer nameplate of 14 MVA during 26 hours. The peak load was 15.83 MVA. In 2026, the transformer is expected to be overloaded for ~249 hours.

The first distribution service analyzed is capacity deferral, where the storage is used to defer an investment to a new transformer. A 10-year deferral time horizon from 2017 through 2026 was considered with an annual load growth of 2%. To defer the investment, the storage was required to maintain the transformer loading below a limit that was allowed to linearly grow from the manufacturers nameplate value of 14 MVA in year 2017 to ~16 MVA in 2026. In other words, the transformer loading was allowed to increase in order to meet the future load growth on that substation.

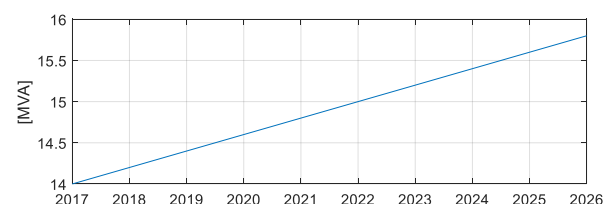


Figure 3. Transformer loading limit from 2017 through 2026

Since the transformer power factor is fairly low during the peak load times, it is essential to consider the impact of reactive power on the capacity deferral requirements. Table 1 summarizes the storage and reactive power compensating capacitor requirements for the cases considered. The key findings from the cases are listed below:

- **Case 1:** There is no reactive power compensation in this case. In other words, no capacitors are required and storage PCS does not need to be oversized. On the other hand, the resulting storage MW and MWh power requirements are impractically large.
- **Case 2:** In this case, ESS PCS perfectly compensates for the transformer reactive power without no support from capacitors. The resulting storage MW and MWh requirements are reasonable but ESS PCS needs to be oversized by impractical 300%.
- **Case 3:** In this case, (step-wise adjustable) capacitor banks keep the power factor close to/at unity. The

resulting storage MW and MWh requirements are identical to case 2 and no ESS PCS oversizing is required. However, the total required capacitor bank rating is ~6.5 Mvar.

- Case 4:** In this case, capacitor banks are used to keep the power factor  $\geq 0.97$  and storage PCS is not used to compensate for the remaining reactive power. The resulting storage MW and MWh requirements are much larger than in case 2 albeit smaller than in case 1. On the other hand, the total required size of capacitor bank(s) has reduced to ~2 Mvar.
- Case 5:** In this case, capacitor banks are used to keep the power factor  $\geq 0.97$  and storage PCS is used to compensate for the remaining reactive power. The resulting storage MW and MWh requirements are identical to case 2 and the storage PCS still needs to be oversized by >200%. The capacitor bank requirement is identical to case 4.
- Case 6:** This case is identical to case 4 except that reactive power is not assumed to grow from 2017 to 2026. This assumption is reasonable since the current peak load time power factor is very low likely due to some induction motor loads. The resulting capacitor bank size requirement has decreased compared to case 4.
- Case 7:** This case is identical to case 5 except that reactive power is not assumed to grow from 2017 to 2026. The resulting capacitor bank size requirement has decreased compared to case 5.
- Case 8:** This case is identical to case 4 except that capacitor banks are used to keep power factor  $\geq 0.99$ . The resulting storage MW, MWh, and MVA requirements are smaller than in case 6 but capacitor bank size requirement has increased to ~4 Mvar.
- Case 9:** This case is identical to case 7 except that a capacitor banks are used to keep power factor  $\geq 0.99$ . Compared to case 7, the storage requirements PCS capacity requirement has decreased to 3.29 MVA and the capacitor bank size requirement has increased to ~4 Mvar.
- Case 10:** This case is identical to case 8 except that reactive power is assumed not to grow. The resulting storage requirements are identical to case 8 but the capacitor requirement is somewhat lower.
- Case 11:** This case is identical to case 8 except that reactive power is assumed not to grow. The resulting storage requirements are identical to case 10 but the capacitor requirement is somewhat lower.

The analyzed scenarios emphasize the influence of load growth assumptions and the importance of considering reactive power compensation when performing storage sizing for capacity deferral applications. The analyzed scenarios also highlight the tradeoffs between the storage active power/energy, storage PCS oversizing, and the distribution system reactive power compensation. Allowing for some PCS oversizing can considerably reduce the capacitor bank requirements while

simultaneously allowing to use the storage PCS for other applications. In this paper, case 11 is followed, where the storage is sized to 2 MW – 10 MWh (5hr) and the storage PCS is oversized by 50%. Additionally, two 1.2 Mvar capacitor banks are installed on the feeders supplied by the substation.

Table 1. Energy storage sizing scenarios

Case #	Mvar Load Grows	Caps Keep PF Above	ESS Compensates Remaining Mvars	Growth in Mvars	ESS Requirements			Caps Mvar Req.
					MW	MWh	MVA	
1	Yes	No Caps	No	Yes	3.34	20.65	3.34	0
2	Yes	No Caps	Yes	Yes	2.08	10.17	6.52	0
3	Yes	1.00	N/A	Yes	2.08	10.17	2.08	6.52
4	Yes	0.97	No	Yes	2.73	15.43	2.73	1.95
5	Yes	0.97	Yes	Yes	2.08	10.17	4.94	1.95
6	No	0.97	No	No	2.73	15.43	2.73	1.06
7	No	0.97	Yes	No	2.08	10.17	4.94	1.06
8	Yes	0.99	No	Yes	2.29	11.79	2.29	3.76
9	Yes	0.99	Yes	Yes	2.08	10.17	3.29	3.76
10	No	0.99	No	No	2.29	11.79	2.29	2.74
11	No	0.99	Yes	No	2.08	10.17	3.29	2.74

Figure 4 shows the storage operating profile and the storage state-of-charge (SOC) over the analyzed time period. Clearly, the capacity deferral service is needed very seldom. This motivates the storage use for secondary distribution services analyzed as follows.

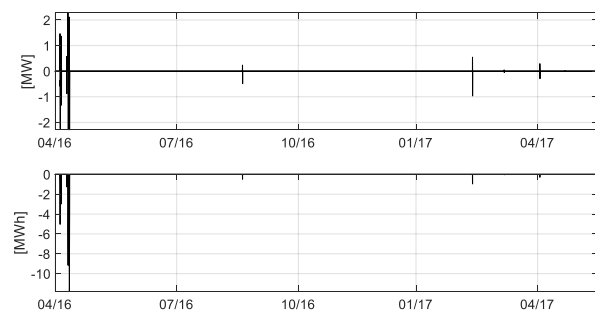


Figure 4. Case 11 year 2026 storage operating profile (top) and SOC (bottom)

### Transformer Tap Change Operation Reduction

The second analysed storage distribution service is reducing the transformer load-tap changer (LTC) operations. Reducing the tap operations helps to avoid maintenance work necessary to care for the wear and tear in the tap changer operation. Figure 5 illustrates the voltage change in  $V_{pu}$  and in LTC taps with respect to storage PCS Mvar injection. A +/-1 Mvar reactive power injection causes a voltage change in the order of -2/+2 LTC tap equivalents. This simple calculation illustrates the theoretical feasibility of reducing the tap operations. To reduce the tap operations in practice requires to control the storage PCS reactive power output considering the storage active power output, LTC controls, feeder load, and feeder other DER. The benefits

and costs of this distribution service should also be weighted. Detailed technical and economic analyses of the tap operation reduction are out of the scope of this paper. Here it suffices to show its theoretical feasibility.

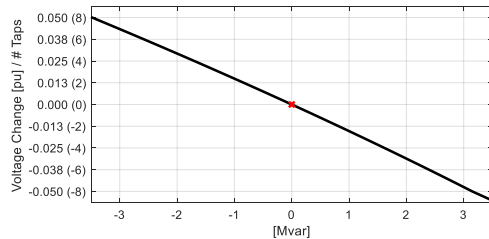


Figure 5. Storage Mvar injection impact on the storage location bus voltage

### Power Quality Improvement

The third analysed distribution service was power quality (PQ) improvement, where the storage objective is to boost the distribution voltages during voltage sags to avoid the tripping of sensitive customer equipment on adjacent feeders. A simple feasibility study on the power quality use case was performed by analyzing the storage Mvar injection impact on the voltages on adjacent feeders. Figure 6 illustrates the steady-state voltage changes on a feeder downstream of the storage location with respect to the storage PCS var injection. The results are very similar for the other feeders. The voltage changes are relatively independent of the feeder location. Moreover, very large storage Mvar injections are required to considerably move voltages. For example, a 1 Mvar (3 Mvar) capacitive reactive power injection would boost the feeder voltages by ~0.015 pu (~0.040 pu). A 0.015 pu voltage boost can be achieved also by simply regulating the LTC from the current tap to the highest tap.

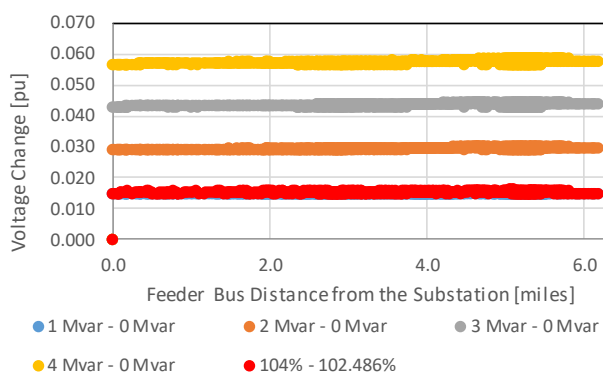


Figure 6. Storage Mvar injection impact on the voltages on one of the downstream feeders

The exact storage PCS reactive power requirements for the PQ service depend eventually on the following three factors: 1) the sensitivity of the sensitive customer equipment on the feeder (i.e. what depth of voltage sags do the equipment tolerate), 2) the customer voltage before the voltage sag that depends on the feeder head voltages and voltage drop/raise on the feeder, and 3) the depth of the voltage sags to be mitigated. Independent of

these factors, a large storage PCS reactive power capacity is likely needed to mitigate the impacts from most voltage sags. A more detailed PQ assessment is out of the scope of this paper.

### Distribution Loss Reduction

The fourth and the last distribution service considered was to reduce the distribution losses. Capacity deferral and PQ distribution services are needed very infrequently and thus, have negligible impact on the distribution losses. LTC tap operation reduction distribution service has the potential to either increase or decrease distribution losses but the impact is not expected to be significant. Reactive power compensation (with capacitors and storage PCS) is expected to have the largest impact on the distribution losses. Since the storage is placed at the substation at the transformer secondary, the storage reactive power compensation is not expected to have major impacts on the losses of the downstream feeders. Instead, the storage reactive power compensation will mainly influence the transformer losses. The highest possible reduction in the transformer losses before and after perfectly compensating for the transformer reactive power (with downstream capacitors and the storage):

$$\Delta P_{loss} = \frac{R_{SC}(P_{load}^2 + 0)}{(0.95V_{LL})^2} - \frac{R_{SC}(P_{load}^2 + Q_{load}^2)}{(0.95V_{LL})^2}$$

The economic value in the reduction in losses was estimated to be in the order of \$1-3k per year, which is very small compared the value of the other distribution services and the storage system costs. Moreover, this analysis does not consider the storage PCS losses.

### CONCLUSIONS

The work in this paper details the analysis for integrating a utility scale BESS at a substation and how the storage can be controlled and operated to realize stacked benefits. The impact analysis shows that BESS can be utilized to defer a substation transformer upgrade. Combination of BESS and capacitor banks can mitigate the reactive power requirements and at the same time reduce the transformer tap operations and improve power quality. This analysis will be used as a reference guide for Avangrid to procure the BESS and ultimately commission the system in 2019.

### REFERENCES

- [1] Southern California Edison: "Moving Energy Storage from Concept to Reality", 2011
- [2] EPRI Report 3002011779 "Integrating Energy Storage with Photovoltaic distributed generation within distribution system", September 2017