Community-Scale Solar Plus Thermal Storage and Demand-Response

A Modeling Study of Local Grid Benefits

Community Solar Value Project
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Powered by SunShot U.S. Department of Energy

Summary

Working with the team from the Community Solar Value Project (CSVP), a program co-funded by the U.S. DOE SunShot program, Public Service Company of New Mexico (PNM) has examined the idea of combining community-scale solar with storage and demand-response (DR) measures. This strategy has been discussed in the utility industry, as a means of capturing numerous benefits, from managing system peaks to offering customers more clean-energy choices, as renewable-energy penetration increases. Another benefit might be the opportunity to site solar and solar-plus measures to capture grid benefits. Thus, this study examines an opportunity to mitigate low-voltage issues on a feeder comprised primarily of residential loads. Might distributed solar generation plus thermal storage and DR benefit this circuit, or might they create new problems?

PNM modeled the impact on a distribution feeder of multiple combinations of solar arrays of varying sizes with control of residential air conditioners and electric water heaters. In each scenario, PNM evaluated the resulting improvement in voltage levels on each distribution transformer during the period of low voltage (primarily, late afternoon and early evening). While neither DR alone nor a solar array alone could mitigate all low-voltage issues, the combination of a mid-sized solar array and simple DR control strategies on thermal storage eliminated all instances of low voltage. The modeling approach used here may be extended and applied in other studies at PNM or other utilities, in evaluating novel combinations of renewables and load flexibility to address distribution issues.

Introduction

PNM is New Mexico's largest electric utility, serving over 525,000 customers in a state with relatively low population and a large amount of natural resources. Given the natural resources in the state, it is not surprising that PNM's customers have a high interest in renewable energy. In fact, Albuquerque was noted in a recent U.S. Department of Energy SunShot Solar Industry Update as being in the top 5 cities in the nation in terms of per capita PV installed.[1] In a proactive project that began in 2010 and was completed in 2011, PNM was a very early pioneer in studying how energy storage may be able to work together with distributed renewables to help improve their value. That effort, called the Prosperity Energy Storage project, has been developed as part of the U.S. Department of Energy (U.S. DOE) Smart Grid Demonstration Grants in the Energy Storage Program.

The Prosperity project was designed and built as a 500-kW/1 MWh utility-scale battery storage system that interacted directly with a co-located 500 kW PV solar array. In this project, PNM researchers looked at multiple value streams. One such value stream is related to smoothing power output, in response to changes in PV system output e.g., from intermittent cloud cover; The system also has the capability of storing PV system output at high solar production times for use at times that are more aligned with utility system peak usage times.

While battery energy storage is an extremely flexible resource, in many markets it is still a costly solution. Thus, PNM's experience with Prosperity prompted an investigation into other resources that could combine with PV to provide similar benefits at a lower cost. In particular, might there be alternative resources for balancing shorter term fluctuations, allowing the battery system to focus on its energy applications, and how such alternative resources could help mitigate some of the locational issues that arise with distributed generation. As part of this investigation, PNM modeled some scenarios utilizing a community-scale solar (CS) project coupled with demand-response (DR) resources. The scenario could be extended to implementation through a model that promotes community solar with companion measures (utility-side storage plus DR); however, this modeling exercise was focused only on technical impacts.

PNM had identified a feeder in its service territory that already was displaying voltages at certain times of the day that were below PNM's design criteria (ANSI Range-A Voltage Limits). The low voltages were identified during routine planning evaluation and traditional system improvement approaches were implemented to mitigate the low voltages. However, the goal of this analysis was to investigate the possibility of using DR and CS resources, as opposed to the traditional approaches to mitigate low voltages that occur as a result of normal load growth.[2] The analysis presented in this report assumes all available DR resources participated in the program. Two DR resources were evaluated in

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[1] Robert Margolis, David Feldman, Daniel Boff, "Q4 2016/Q1 2017 Solar Industry Update", page 33, U.S. Department of Energy SunShot, April 25, 2017

[2] The analysis and conclusions highlighted in this report were not fully vetted through PNM's Distribution Planning Department. The findings and conclusions in this report are those of the authors and do not represent the official position of PNM.

this analysis, controlled HVAC units (residential air conditioning) and controlled electric hot water heaters (EHWH). The circuit modeled is primarily residential, but these CS and DR measures may also be targeted to a commercial market.

As indicated below, the scenario utilized for this study represents a first-step in the technical assessment of possible CS grid benefits. The research questions are simply these:

1) Would a distribution circuit that is experiencing low voltage be a candidate for a solar-plus-DR (with thermal storage) strategy?

2) If a solar-plus-DR strategy were suggested for a circuit experiencing periodic low-voltage characteristics, is there an ideal configuration, in terms of solar-project scale?

3) What are the likely synergistic effects in the situation described, of adding one or more DR measures, plus thermal storage, along with the addition of distribution-scale solar generation?

In preparing this analysis, the authors worked with the Community Solar Value Project (CSVP), which is a U.S. DOE SunShot awardee. CSVP has worked with utilities on a range of DR and storage options that could be used as companion measures with community-scale solar, primarily in the range of 500-kW to 10 MW. Some of the approaches discussed in this analysis were developed based in part on CSVP's work with other utilities, and the authors hope these results will be of use to utilities considering similar options. As noted below, CSVP has identified numerous DR technologies and customer-side storage options that are readily available and have various, flexible control characteristics, as well as customer-appeals. CSVP also has recommended fully utilizing inverter technology and adding strategic solar-design improvements. Not all of these available high-value options are modeled for this study. In effect, this study represents a "first gate" in the path to establishing a community-scale solar-plus strategy

The following cases were modeled:

- Base Case
    - Demand response and community solar resources not evaluated
- Community Solar Only
    - Only community solar resources evaluated.
    - The size of the PV generator was increased from 1MW-9MW at 1MW increments.
    - The location of the community solar site was static.
- Demand Response Only
    - Only demand response resources evaluated.
    - Operation of the HVAC units were advanced or deferred in an effort to mitigate voltage issues.
    - The operations of the EHWH units were shifted outside peak loading periods.
- Community Solar plus Demand Response

- Demand response resources evaluated in conjunction with community solar resources
- The operation of the HVAC units were advanced or deferred in an effort to mitigate low voltage issues.
- The operations of the EHWH were deferred between peak loading periods.

Demand Response Resources

Company-sponsored third party load research identified HVAC saturation at 32.3% and EHWH saturation at 9.1%. For the purposes of this analysis it was assumed all available HVAC and EHWH units participated in the DR program. This resulted in 763 customers with HVAC units and 212 customers with EHWH units. HVAC and EHWH units were randomly assigned to distribution transformers according to the previously identified saturation levels. Hypothetical load profiles for the DR resource were randomly generated and 24-hour load profiles for residential loads were developed. For the purpose of this analysis DR loads were shifted from on-peak to off-peak periods. The total baseline DR load profile developed for this analysis is highlighted in Figure 1.

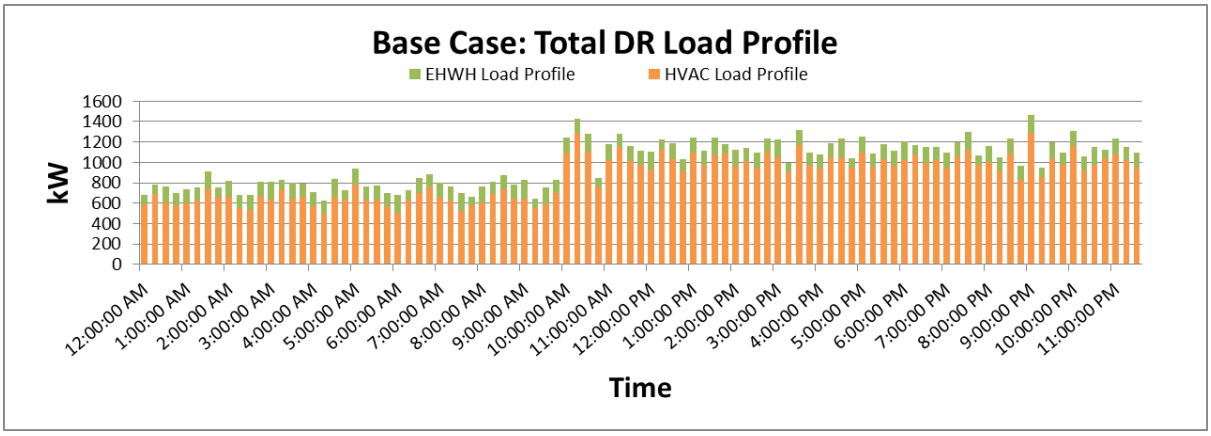

Figure 1 - Total DR Baseline Load Profile

HVAC Units

Metered customer HVAC load data was not available for use in this analysis. Therefore, baseline hypothetical HVAC load profiles were generated. An example of a generated HVAC load profile is highlighted in **Error! Reference source not found.**. All HVAC units were simulated using a 5.6 kW demand. The ON duration time for HVAC units was set for 15 minutes and the OFF duration time was randomly generated between 30-90 minutes.

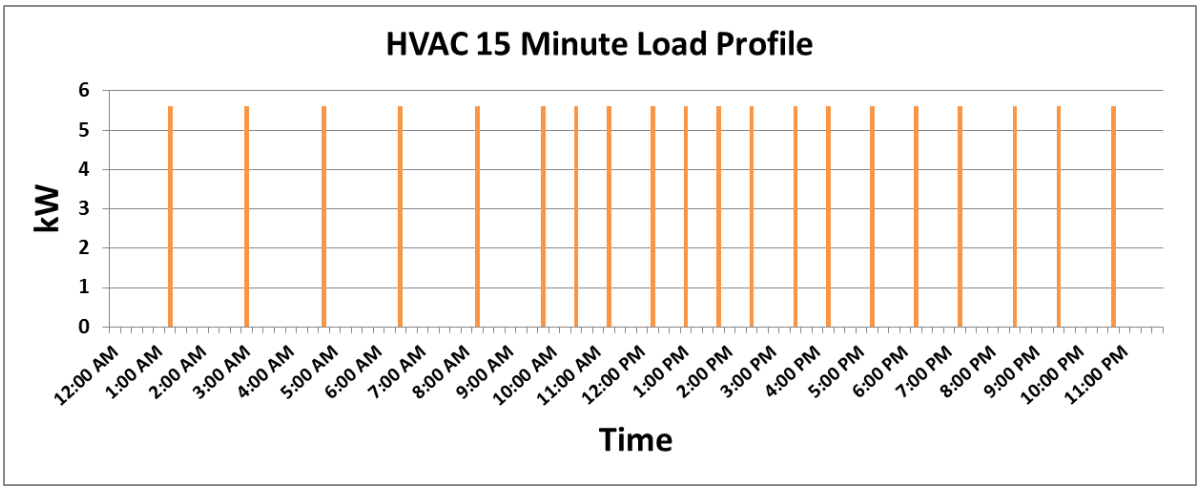

Figure 2 - Generated HVAC Baseline 15 Minute Load Profile

HVAC loads were controlled in one of two ways: (1) for the time interval between 12:00 PM - 6:30 PM individual HVAC loads were advanced 15 minutes compared to the baseline profile, ensuring distribution voltages remain within the planning criteria, (2) for time intervals between 6:30 PM - 12 AM individual HVAC loads were delayed 15 minutes, ensuring distribution voltages remain within the planning criteria. For example, for the baseline HVAC load depicted in Figure 2 the corresponding controlled HVAC load profile is identified in Figure 3.

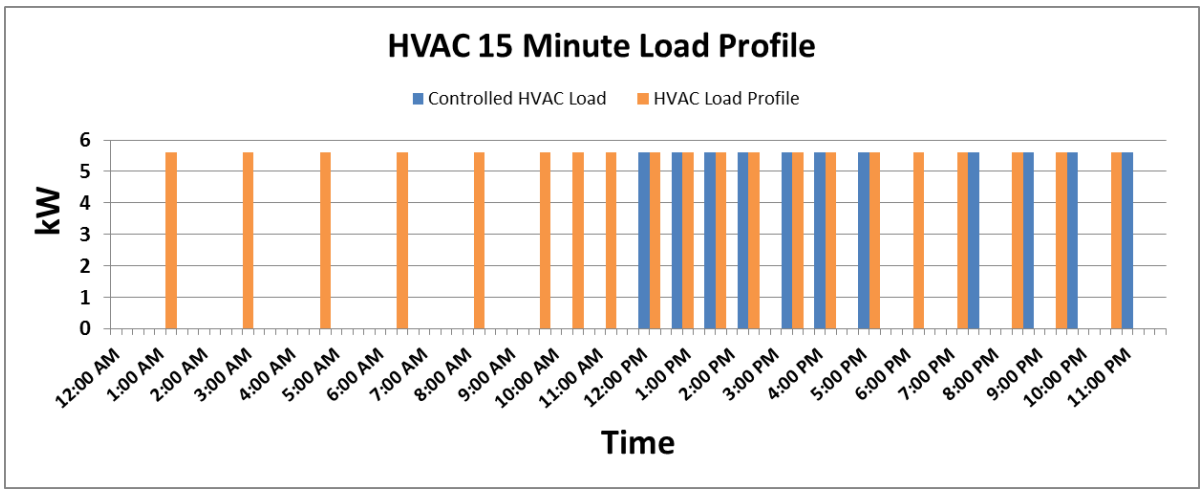

Figure 3 - Controlled HVAC Load Profile Example

EHWH Units

Metered customer EHWH load data were not available for use in this analysis. Therefore, baseline hypothetical EHWH load profiles were generated. An example of a generated EHWH load profile is highlighted in Figure 4. The EHWH loads were generated using a demand of 3.9 kW. The ON duration time for the EHWH was set for 15 minutes and the OFF duration time was set for 75 minutes. The initial ON operation for the EHWH were randomly generated. For the DR controlled cases evaluated in this analysis EHWH loads

were completely curtailed between the hours of 5:00 PM – 10 PM. For example, for the baseline EHWE load depicted in Figure 4 the corresponding controlled EHWH load profile is identified in Figure 5.

Note that today's grid-interactive electric water heater technologies can support a more flexible, load-responsive control scenario than those modeled here. As a first-step analysis, this study relied on basic time-of-day type control strategies and assumed only existing water heaters, retrofitted with controls that do not require customers to have advanced electronic meters. Similarly, the HVAC control strategy selected for this modeling effort was intended to be readily achievable, using existing technologies and simple changes to existing protocols. (See additional CSVP resources for more on DR and customer-side storage options.)

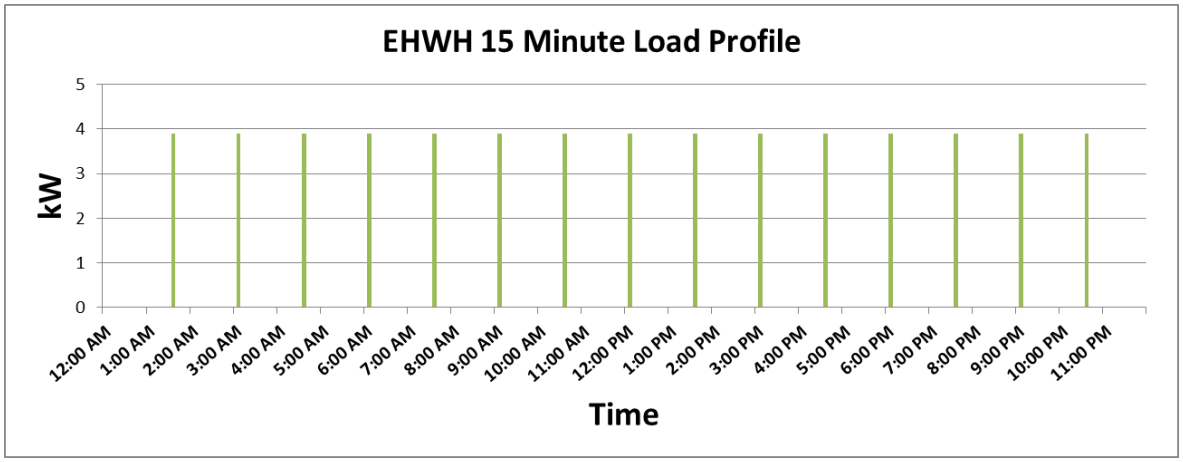

Figure 4 -Baseline EHWH Load Profile

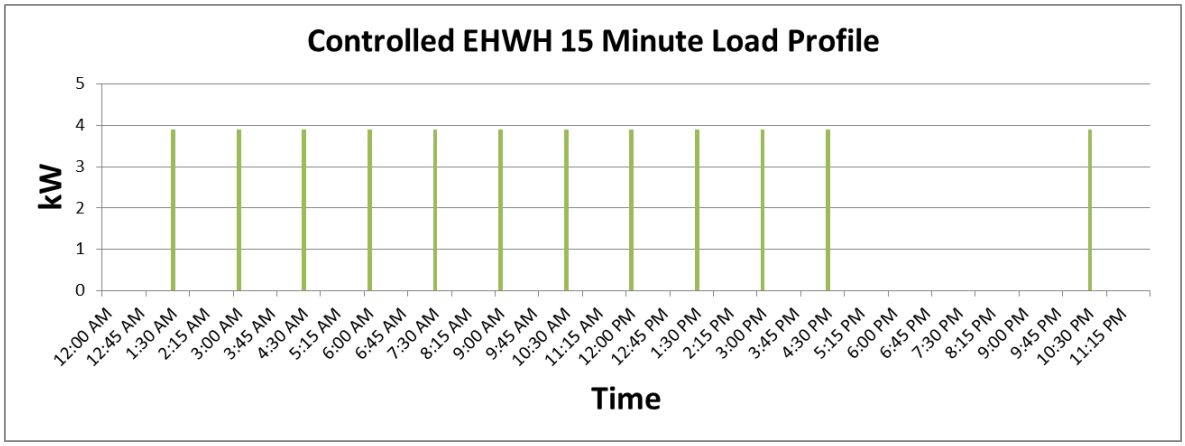

Figure 5 - Controlled EHWH Load Profile Example

Feeder Distribution Voltage

The company-accepted criteria for appropriate distribution voltage is the American National Standard Institute (ANSI) Standard C84.1. The standard specifies voltage ranges

for normal (Range-A) and emergency (Range B) conditions. Range-A defines the service voltage as a minimum of 114 volts and a maximum of 126 volts.

A maximum voltage drop of 4% is the company design limit from the distribution transformer primary to the customer service meter. Furthermore, PNM typically sets substation transformer secondary voltages at 2.0% - 2.5% above 120 volts nominal. Applying the company voltage drop design limits to the ANSI C84.1 Range-A limits results in a minimum voltage requirement of 118.7 volts at the primary distribution transformer high side to ensure a utilization voltage of 114 volts at the customer meter. Furthermore, PNM generally does not model distribution transformers and customer service drops. For the purpose of this analysis, distribution transformers primary voltages below 118.7 volts and above 126 volts are considered outside Range-A.

Feeder Model

The feeder used in this analysis is identified as HAMI13. During routine planning evaluation, the Synergi feeder model identified low voltages below the ANSI C84.1 Range-A lower limit during peak loading conditions. The low voltages were concentrated to A-phase and B-phase laterals located at the end of the feeder. The Synergi voltage heat map is identified in Figure 6. Mitigating the low voltages required the following system improvements:

- Relocating an overhead 1200 kVAR fixed capacitor
- Installing a new pad-mounted 1800 kVAR switched capacitor bank
- Transferring a single phase loop from the B-phase to the A-phase.

Figure 6 - Synergi HAMI13 Feeder Model Voltage Profile

OpenDSS Model Development

The Synergi feeder model was converted to OpenDSS format using scripts developed in Visual Basic for Application (VBA). A one-to-one conversion was performed between the Synergi feeder model and the OpenDSS equivalent format. A visual comparison between of the circuit plot models is shown in Figure 7. Power flow analysis was done using OpenDSS, driven by VBA through the COM interface.

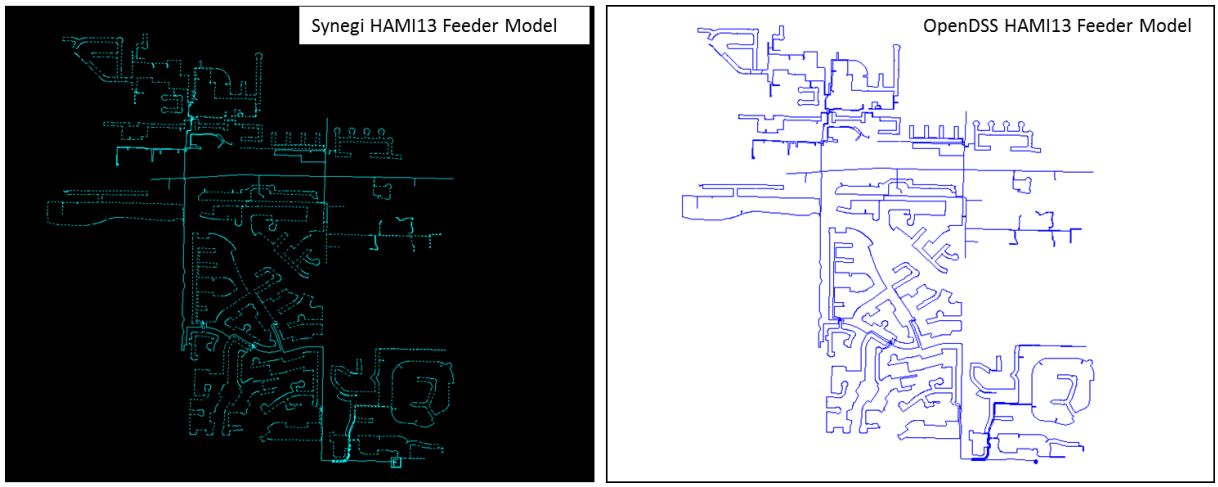

Figure 7 - OpenDSS and Synergi Feeder Circuit Plots

OpenDSS Base Model

Supervisory Control and Data Acquisition (SCADA) feeder load data corresponding to the peak loading day was used to develop residential load profiles. The residential transformer load profiles were developed by treating the EHWH and HVAC units as spot loads and allocating SCADA 15 minute feeder load data according to connected KVA. Modeling the DR load as spot loads ensured that only non-deferrable loads were captured in the allocation factors. The resulting OpenDSS model feeder load profile, with DR resources and non-deferrable loads identified is shown in Figure 8.

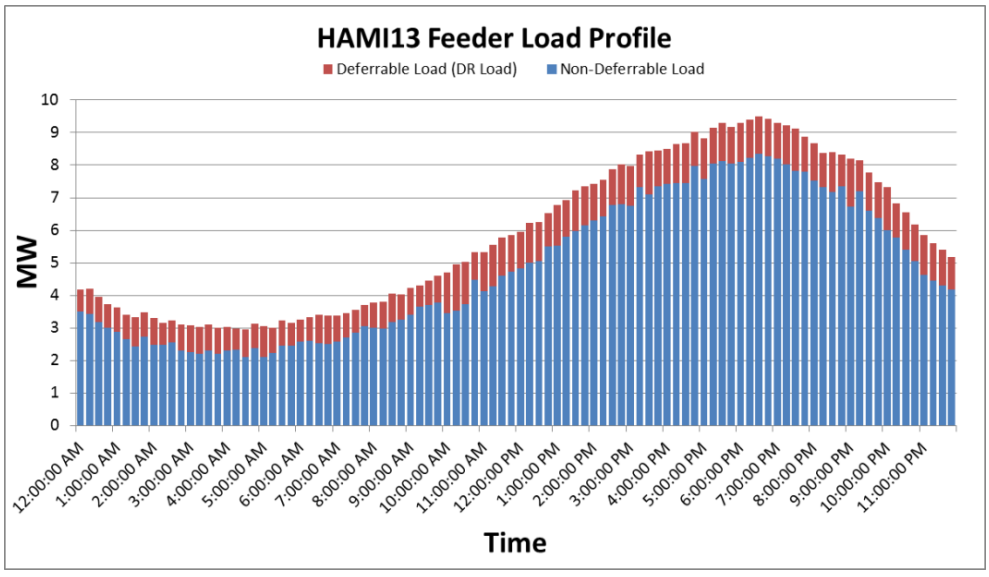

Figure 8 - OpenDSS Feeder Load Profile

The base case OpenDSS feeder model developed for this analysis identified multiple single-phase laterals with primary distribution voltages below the ANSI C84.1 Range-A limit. The Synergi and OpenDSS distribution voltage profile results are identified in Figure 9. Both

models identify systemic low voltage, clustered on single phase laterals at the end of the feeder.

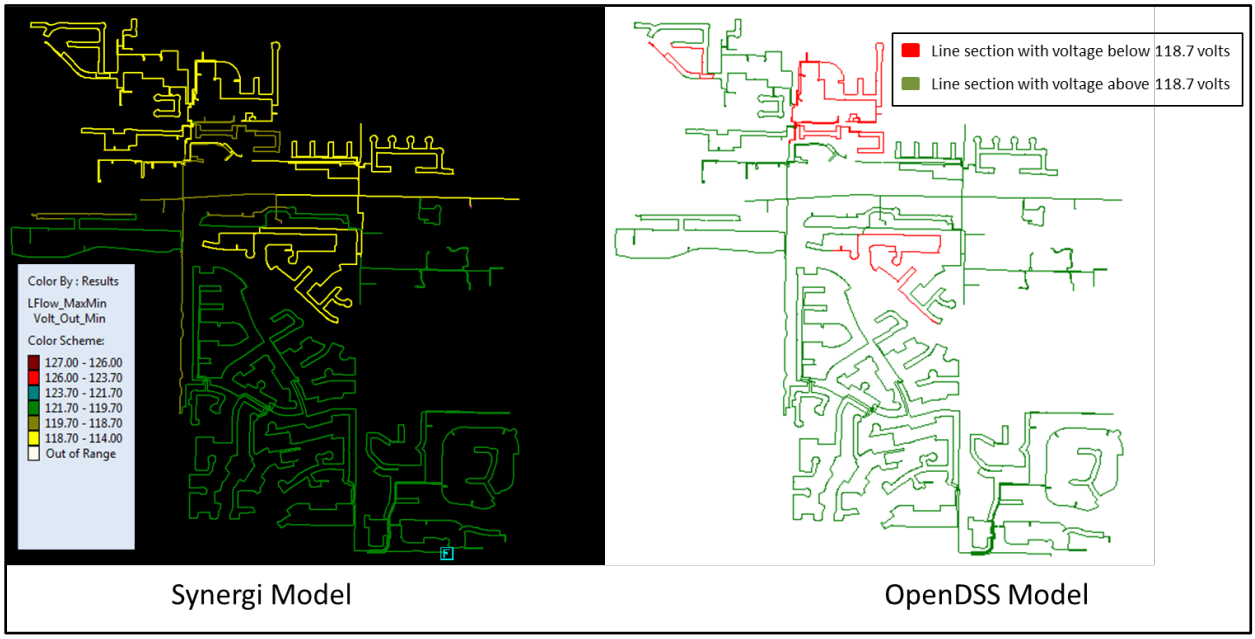

Figure 9 - Synergi & OpenDSS Voltage Circuit Plots

The Base Case OpenDSS minimum transformer primary voltage and feeder load profile are graphed in Figure 10. The feeder peak of 9.4 MW occurred at 6:30 PM. OpenDSS analysis results identify transformer primary voltages below the ANSI C84.1 Range-A lower limit between the hours or 4:00 PM and 8:00 PM. The identified time interval also corresponds to the peak feeder loading interval as identified in Figure 10.

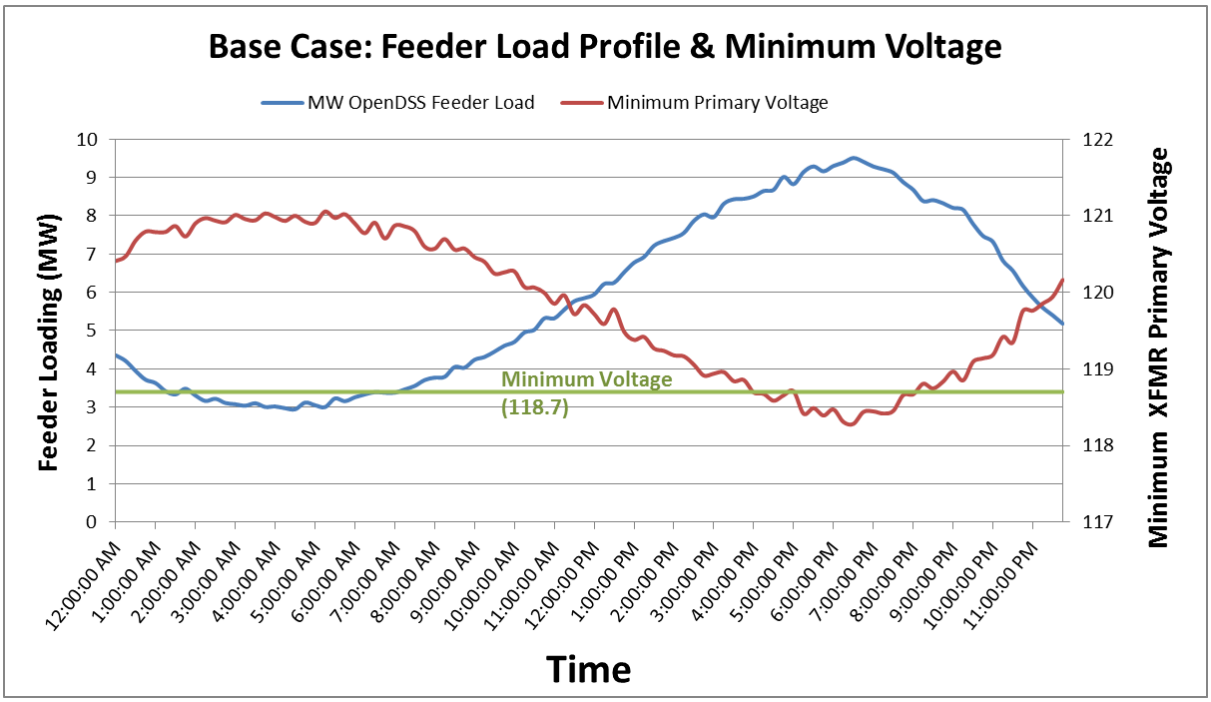

Figure 10 - OpenDSS Feed Loading and Minimum Transformer Primary Voltages

The total number of transformers with primary voltages below the ANSI C84.1 Range-A lower limit of 118.7 volts is highlighted in Figure 11. The number of transformers with primary voltages below the ANSI C84.1 Range-A lower limits peaks at 6:45 PM with 58 transformers. The majority of low voltages occur between 5:15 PM-7:30 PM. The location of transformers with voltages below Range-A are identified in Figure 12. The transformers are located at the end of the feeder on single phase laterals.

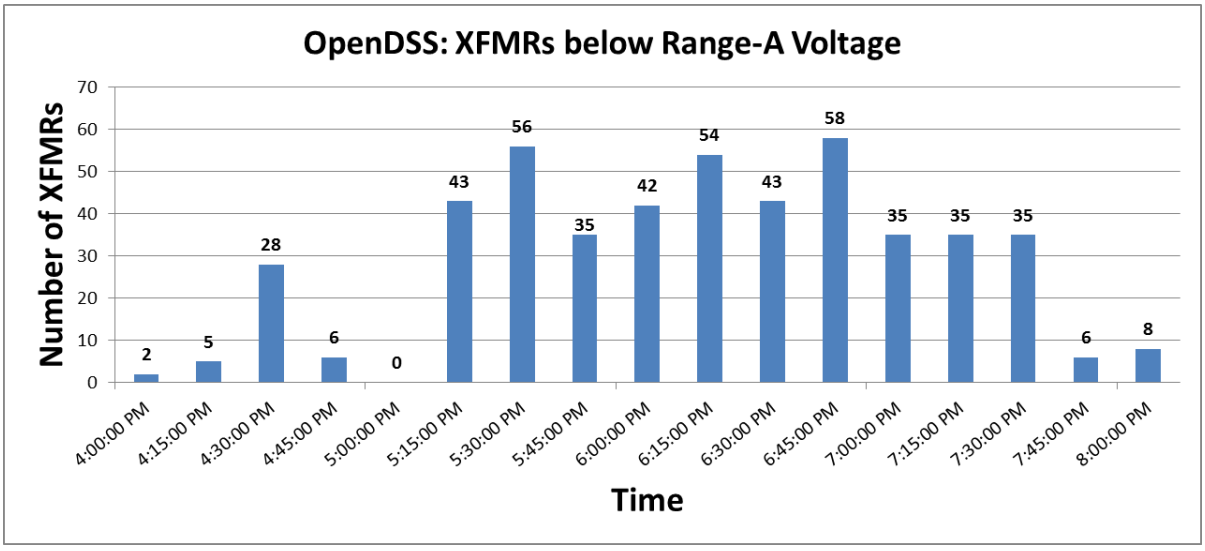

Figure 11 - Base Case: Transformers with Primary Voltage below 118.7 volts

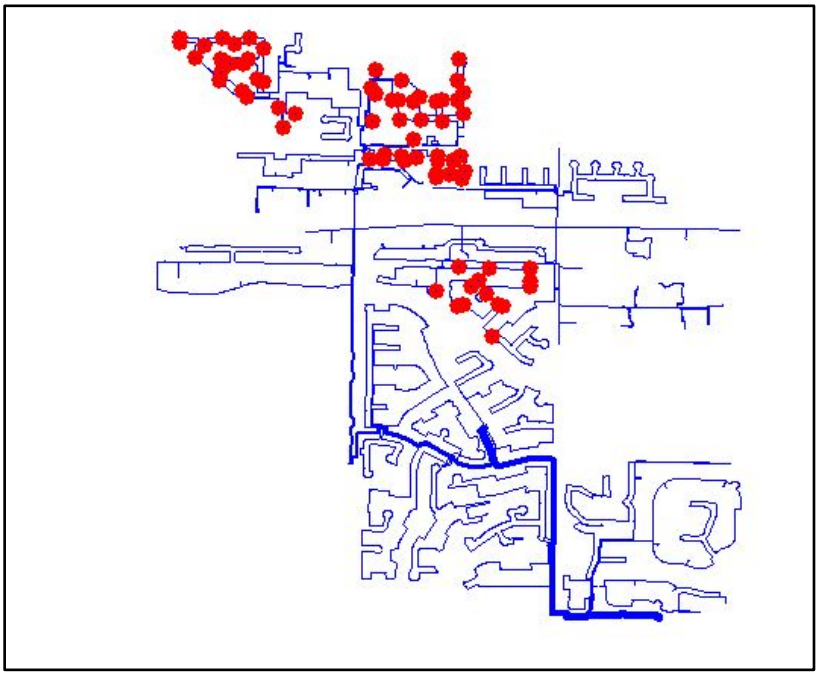

Figure 12 - Base Case: Location of Transformers with Low Voltages

Analysis

Demand Response Only

Controlling DR resources marginally decreases the number of transformers with primary voltages below the ANSI C84.1 Range-A lower limit of 118.7 volts. A comparison between the numbers of transformers with voltages below the design criteria for both the DR controlled case and the Base Cases are highlighted in Figure 13. Controlling DR resources results in voltages above the design criteria for instances before 4:00 PM and after 7:15 PM.

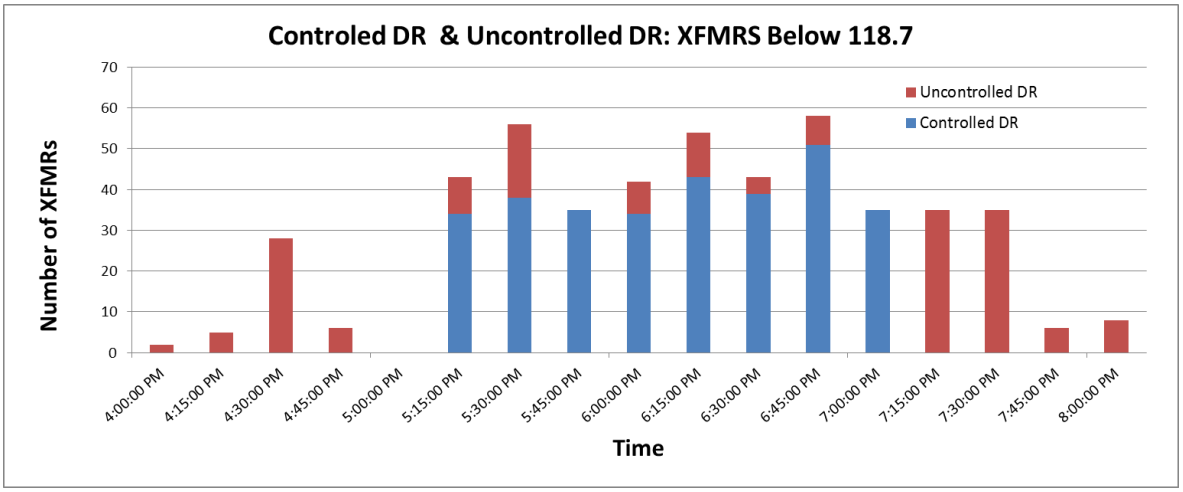

Figure 13 - DR Controlled Case: Transformers with Voltages below 118.7 Volts

The minimum transformer voltages for the controlled and uncontrolled cases are highlighted in Figure 14. The locations of transformers with primary voltages below Range-A lower limits are identified in Figure 15. Compared to the Base Case analysis results, controlling DR resources results in mitigating all transformer primary voltages located on the B-phase later at the end of the feeder.

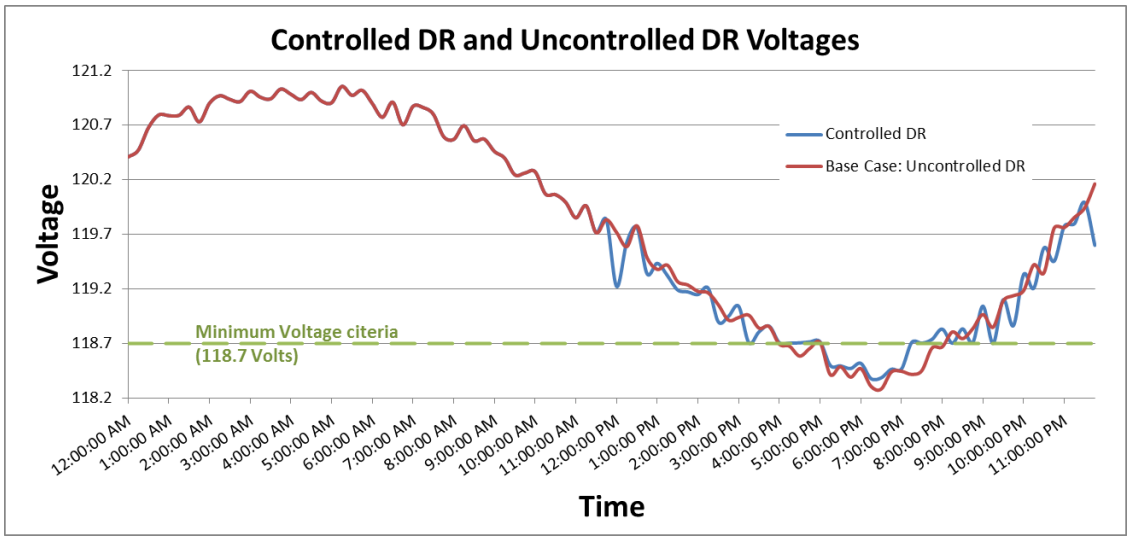

Figure 14 - Minimum Transformer Primary Voltage: Controlled DR vs. Base Case

Figure 15 - Controlled DR Case: Location of Transformers with Low Voltage

Community Solar Only

In this analysis the CS resource was modeled using a unity power factor and assuming an ideal PV generation output for both the CS facility and existing distributive generation. Furthermore, the CS resource was modeled using a static facility location. The CS facility capacity was incremented from 1 MW to 9 MW at 1 MW intervals. Considerable

improvement in transformer primary voltages result in CS outputs of 3-6 MW. However, transformer primary voltages remain below the ANSI C84.1 Range-A lower limit. The minimum transformer primary voltages resulting from various CS facility outputs are graphed in Figure 16.

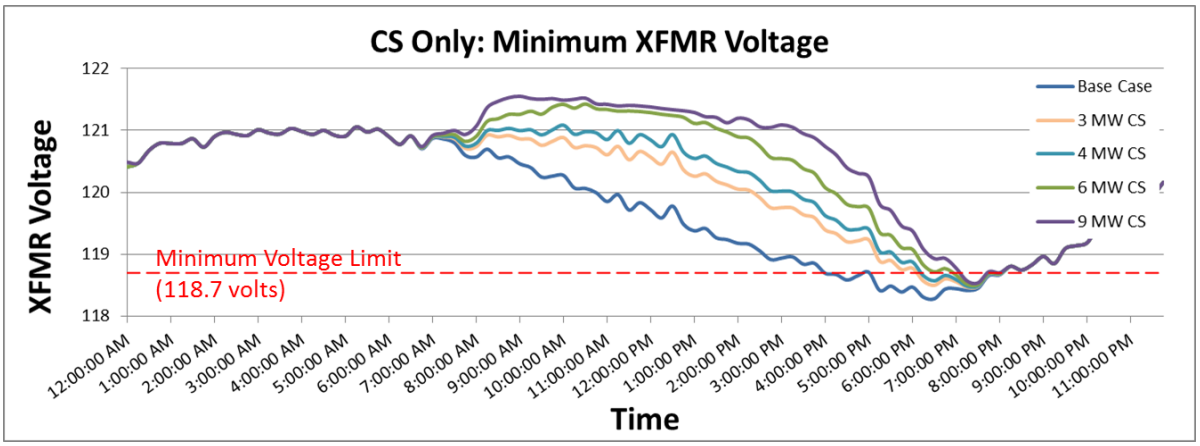

Figure 16 - CS Only Case: Minimum Transformer Primary Voltage

Peak CS output and peak feeder loading are offset by 5 hours with peak CS output occurring at 1:30PM and peak loading occurring at 6:30PM. A CS output of 9 MW results in the majority of transformer primary voltages within the ANSI C84.1Range-A lower limits. However, the output of a 9 MW CS facility provides insufficient voltage support to mitigate low voltages between 7:00 PM - 8:00 PM. For visualization the 9 MW CS output, feeder load profile and remaining number of transformers with voltages below the ANSI C84.1 Range-A voltage limit of 118.7 volts are graphed in Figure 17and the location of those transformers are identified on Figure 18. The remaining low voltages are clustered at the end of the feeder.

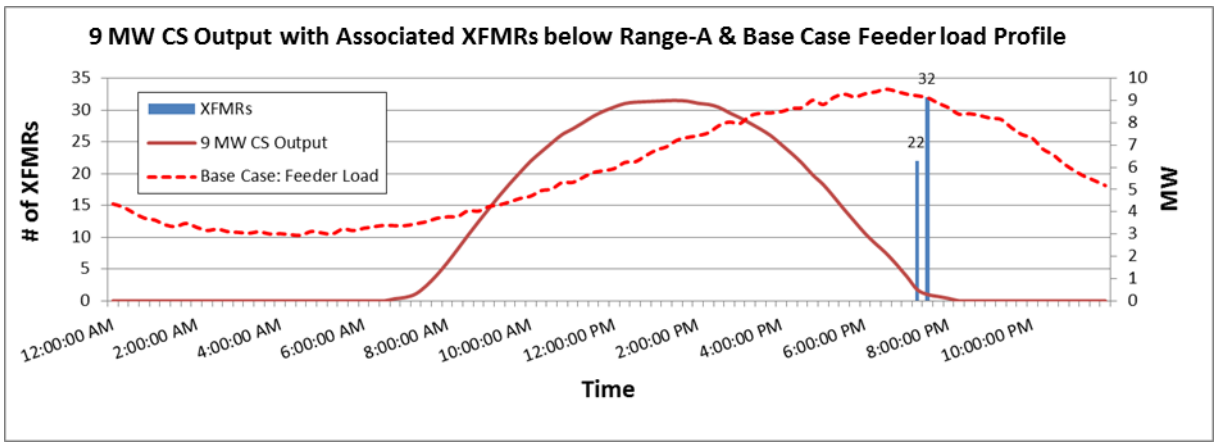

Figure 17 - Base Case Feeder Profile with 9 MW CS Output & Associated XFMRS below Range-A

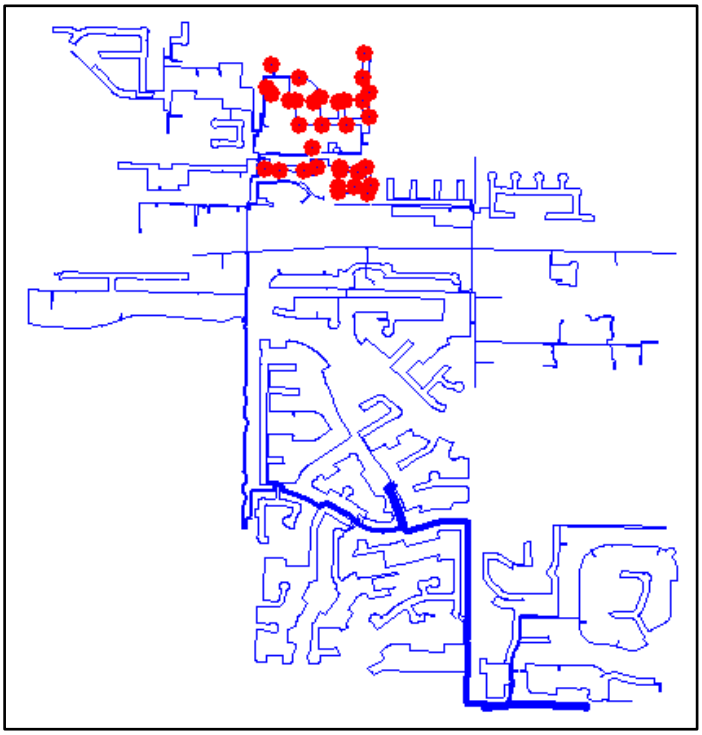

Figure 18 - 9MW CS Case: Location of Transformers with Voltages below 118.7 volts

Community Solar & Demand Response

A combination of CS and controlled DR resources significantly improved primary transformer voltages. Transformer primary voltages for various cases of CS outputs are shown in Figure 19. Utilizing a CS output of 4.5 MW in combination with controlling DR resources ensured all transformer primary voltages are within the ANSI C84.1 Range-A voltage limit requirements.

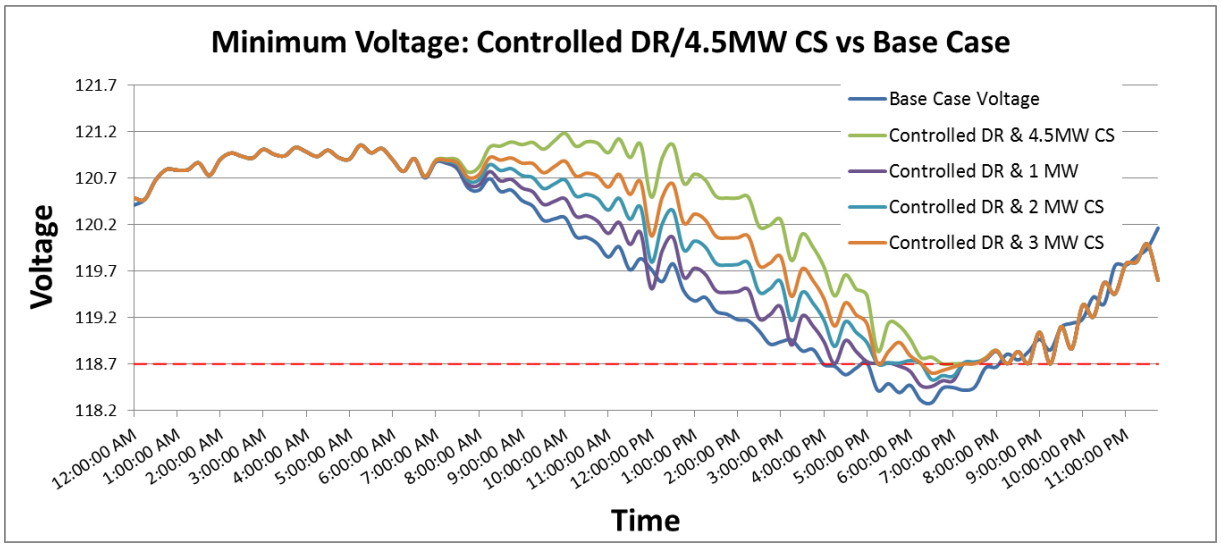

Figure 19 - DR & CS Case: Minimum Primary Transformer Voltage Profile

All DR loads, roughly 1.2 MW, are shifted off peak with a CS output of 4.5 MW.

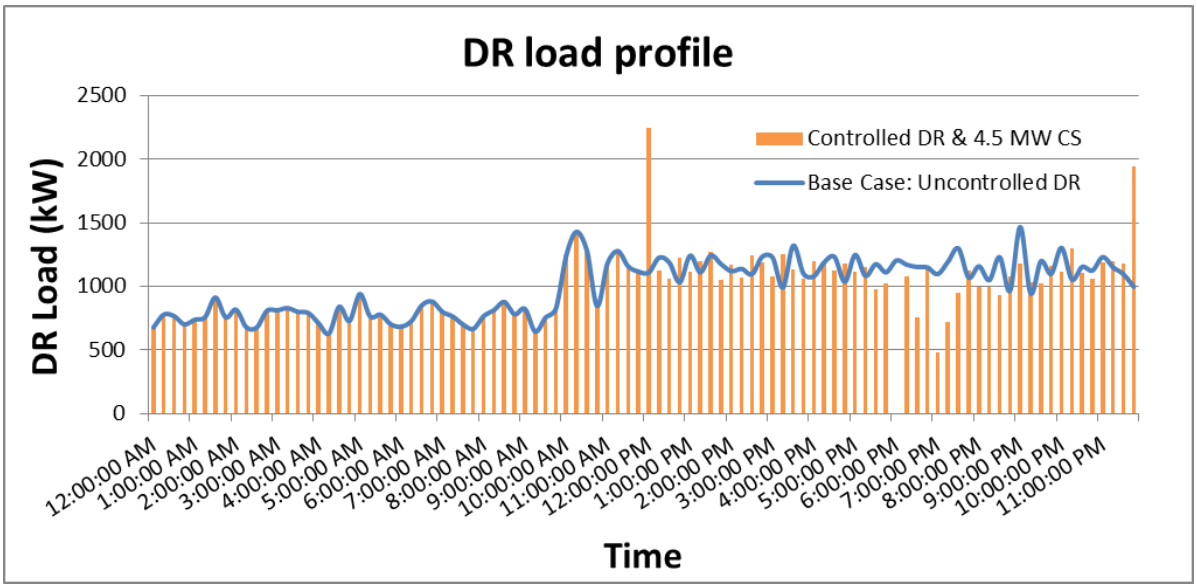

Figure 20 – DR & CS Case: Resukting DR Load Profile

Conclusion

The analysis identified that utilizing a combination of CS and DR resources improved voltages significantly. A CS output of 4.5MW and leveraging DR resources ensured all primary transformer voltages were within planning criteria lower limits. Utilizing CS resources exclusively did provide marginal improvements in feeder voltage at high CS penetration levels but did not ensure all primary transformer voltages were within planning criteria lower limits. Furthermore, controlling DR resources exclusively resulted in marginal improvement in primary transformer voltages but did not completely ensure all primary transformers voltages were within planning criteria lower limits.

This analysis utilized very simple DR control algorithms to shift HVAC and EHWH loads outside of peak loading periods. In this analysis it was assumed that all available HVAC and EHWH units participated in the demand response program. Furthermore, CS resources and distributive generation were modeled using ideal PV generation outputs.

Analysis identified the following results:

- A combination of DR and CS resources significantly improves transformer primary voltages compared to the base case.
- Utilizing DR resources and a CS facility of 4.5 MW ensured all transformer primary voltages were above Range-A lower limits.
- A CS facility with an output of 9 MW marginally decreases the number of transformers with low voltages below Range-A limits before 7:00 PM. However, the output of 9 MW CS facility provides insufficient voltage support to mitigate low voltages after 7:00 PM.

- Controlling DR resources marginally decreases the number of transformers with primary voltages below the Range-A lower limit. Controlling DR resources results in voltages above the design criteria for instances before 4:00 PM and after 7:15 PM.

The simplicity of the control algorithms used in the modeling is encouraging and may indicate that more automated and coordinated control strategies using intra-day feedback could yield improved results, compared to the deterministic time-of-day control strategies modeled in this paper. This type of scenario suggests an analysis for future investigation.

While the analysis did provide some very interesting results regarding the combination of community solar plus DR, and their capability to work in concert to mitigate feeder issues, there is still a dose of reality that must be considered. Some hypotheses around PV installations believe that solar alone could be a possible resource to possibly defer feeder upgrades. In this model, the solar installation did mitigate some low voltage issues, but fell short as the sun was setting when we began to again see the voltage issues we were trying to mitigate. Also demand response, traditionally used as a peaking resource for the bulk electric system, only did a marginal job on mitigating voltage issues on the distribution feeder itself. Additional engineering and solar-plus measures could achieve a grid deferral in some cases, but as this analysis suggests, that would not be a simple undertaking, at best.

The purpose of this study was to investigate the feasibility of utilizing CS and DR resources to mitigate low voltages resulting from normal distribution feeder load growth. For the circuit that provided the basis for this study, actual measure taken to mitigate voltage issues included:

- Relocating an existing overhead 1200 kVAR capacitor bank
- Installing a new pad-mounted 1800 kVAR capacitor bank
- Transferring a single-phase from the B-phase to the C-phase.

Aside from the installation of the 1800 kVAR voltage controlled capacitor, the identified system improvements represent marginable, inexpensive solutions. It would be highly unrealistic to use this problem alone as an argument to install a multi-million dollar community solar array and implement a customer-facing DR program with technology and program administration associated costs. Additionally, while the 4.5-MW array seems ideal for this application, there are several other considerations prerequisite to any construction decision. For example, the size of the array might, from a technical standpoint, also be dependent on the feeder to which it is interconnected, and possibly even on the hosting capacity of that feeder. Land use and business factors, marketing, and program design considerations also would come into play prior to any solar development decision.

Would adding a large solar array and DR program be a cost effective solution for the voltage imbalances on this circuit? In a word, no. However, the evidence is clear that a solar-plus strategy would not, in this case, be a technical impediment. Rather, it could support the utility's commitment to system reliability. It is important to look at programs such as community solar, DR and energy efficiency holistically, and outside the traditional operational and planning silos that exist at many utilities.

Relevant questions for further consideration include:

- Does the utility desire more community-scale solar, in the 500-kW- to 10-MW range?
- Would a community solar implementation model help move more customer solar from the rooftop (where it is generally invisible and non-strategic) to the utility's preferred scale and locations?
- Does the utility have energy efficiency or load management desires or requirements?
- Are there program objectives that need to be met for State requirements?
- Does the utility have a clean electrification initiative? The introduction of DR and storage measures, such as grid-interactive electric water heaters, controlled HVAC, ice storage, and strategic electric vehicle (EV) programs could support greater use of electricity, in an age of rising renewable-energy penetration.
- Does the utility foresee having a greenhouse gas mitigation plan?
- Does the utility Integrated Resource Plan (IRP) call for more DR or renewable resources?

All these are important considerations in looking for opportunities to implement new distributed resource projects and programs, while maintaining reliability and optimization of the utility's distribution system, to ensure quality service to all customers.

About the Authors

Santiago Sena is a distribution system engineer with PNM in Albuquerque, NM.

Jon Hawkins is manager of advanced technology and strategy for PNM Resources, and has participated with the Community Solar Value Project (CSVP) as a member of its Utility Forum, leading the exploration of opportunities to create greater net benefits from solar-plus storage and demand response measures.

Jill Cliburn is the Principal Investigator of the CSVP.

John Powers is the Project Officer of the CSVP.

About the Community Solar Value Project

The Community Solar Value Project aims to increase the scale, reach, and value of utility-based community solar programs by using strategic solar technologies, siting, and design, improving procurement strategies, target marketing, and integrating suitable companion measures, such as demand-response and storage into broad program designs. The project is led by the San Francisco-area energy consulting and analytics firm Extensible Energy, LLC, with support from Cliburn and Associates, LLC, Olivine, Inc., and Navigant Consulting. Utility participants include the Sacramento (California) Municipal Utility District (SMUD), Public Service of New Mexico, and other utilities nationwide. The project is powered by SunShot, under the Solar Market Pathways program of the U.S. Department of Energy. Contact: http://www.communitysolarvalueproject.com; info@communitysolarvalueproject.com

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Disclaimer

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