DERs for Peak Reduction

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Project Overview

Synergy North is pleased to submit this final report to the LDC Tomorrow Fund on the benefits of Distributed Energy Resources (DERs). Synergy North endeavored to integrate three residential DERs into an automated virtual power plant to be used to lower the monthly peak demand at a specific transmission station.

The project was done by using a previously installed Power.House system as well as installing two more systems on the same transmission station. Synergy North then integrated these three installations with the Supervisory Control and Data Acquisition (SCADA) system. The Power.House systems were then used to relieve congestion or provide load in real time. These virtual power plants demonstrated how Synergy North can evolve the local power grid and make use of this dispatchable load during peak periods.

Innovation

Synergy North believes the future of electricity distribution involves distributed energy resources (DERs). DERs provide all local distribution companies and their customers the ability to improve grid resiliency, security and operation. This study will utilize three DERs on Synergy North's supply grid. The DERs will be used as virtual power plants and will provide Synergy North with load that can be controlled and relied upon. The systems can be configured to 'follow' the grid supply to provide load support in near real time during anticipated system peaks. Synergy North believes that this configuration of DERs will allow Synergy North to lower the transmission peak at the stations.

Benefits to LDCs

In reference to February 2018 prepared by Navigant Consulting for the Electricity Distributors Association, titled "The Power to Connect", Synergy North believes this project will help the EDA with the objectives stated within the publication. Specifically, the EDA outlined eight objectives, and Synergy North's proposed project will help contribute to at least three of these objectives, which are listed below:

1) "*Engage members on the Power to Connect vision."*
   The proposed project will help to further the knowledge of DERs in Ontario making this project information available to all Ontario LDCs.
2) *"Develop a cost-benefit analysis framework for evaluation of DER and DER enabling technologies."*

The proposed project will aid any LDC attempting to quantify benefits provided by DERs using actual results and data.

3) "*Facilitate collaboration amongst LDCs, third party DER providers and energy solutions vendors to accelerate efforts for cost-effective deployment of DER and enabling technologies."*
The quantification of these actual results will help to provide all LDCs with a better understanding of DERs and the in-field performance.

Transferability of Results

The results produced by the proposed project will be relevant to all LDCs in Ontario. The challenges for LDCs are similar across the province. There are sections of each LDCs distribution system which experience congestion or supply concerns. DERs will give LDCs another tool to make these sections of their distribution systems more resilient and flexible. Synergy North's proposed project will help other LDCs to identify the benefits they will receive from a DER deployment. In addition, DERs will continue to proliferate in the market. Synergy North believes that utilities must learn to integrate them into the supply grid to maximize the system's potential and the utility's return on investment.

Commercial Development

DERs have become more affordable in recent years, making the business case for commercial DERs more viable. The proposed project will help to identify how LDCs can leverage the load available and the distributed intelligent monitoring from the DERs. While Synergy North does not expect supply to be the only positive benefit from expanding the DER installation, the proposed project is expected to bring clarity to a small subset of LDC benefits. As the expansion of DERs continues in the energy market, Synergy North intends to explore these benefits. To paraphrase section 1.2 of the EDA's "The Power to Connect Paper" (Navigant Consulting 2018), there is a shift occurring from large scale one-way generation to a two-way intelligent grid. Synergy North will use this project to continue to explore the benefits and costs associated with these two-way distributed systems. If the LDCs in Ontario do not take action, Synergy North believes that a significant opportunity will be missed.

The Project

Synergy North wanted to be able to dispatch load during the peak demand of each month. At the time of the study, Synergy North pays the provincial transmitter a fixed amount per kW at the time of the highest peak each month. This would make the attempt to quantify the business case fairly simple. If Synergy North could accurately predict the peak demand each day, any DER could be dispatched to reduce that peak. This method produced the following work plan:

1. Install DERs on the same transmission station (TS) to ensure the effect of peak demand reduction could be maximized.

2. Integrate the control of the DERs into a central system.

3. Dispatch load based on a TS peak prediction.

The Distributed Energy Resources (Power.House)

A single Power.House system consists of rooftop solar panels, a bank of high-capacity, utility-grade batteries to store the power and a master control unit. These units work together to collect solar energy during the day and convert it into electricity. During sunny days, electricity is sent to the battery backup, which is then used in the home or forwarded to the electricity grid for credit. The Power.House software management system determines the routing depending on what is best for the homeowner at that time. The Power.House system also provides reduced exposure to outages and peak electricity rates. It does this by using power from the grid and charging the battery during off-peak times for later use.

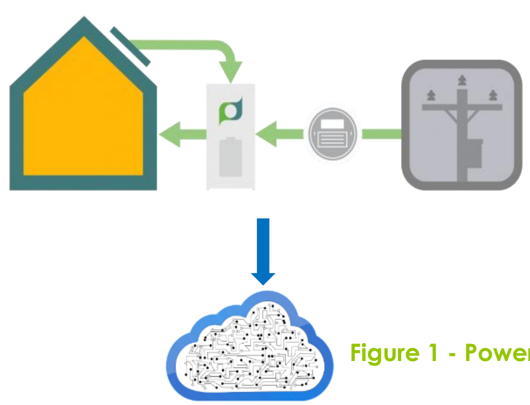

Figure 1 - Power.House System

The Power.House system has been deployed successfully in Ontario. The bulk of these installations are owned and operated by Alectra Inc. Synergy North entered into a MOU with Alectra and commissioned the first installation in Thunder Bay on January 27, 2017. The guidance provided by Alectra, with respect to the installation and commissioning of the initial installation, was invaluable.

Synergy North added two more Power.House systems in Thunder Bay. Synergy North chose to use Power.House as DERs for this study as the systems have the ability to be pre-programmed to provide value to the customer while being available for dispatch on short notice. The Power.House systems also have an advanced programming interface (API), which was leveraged to automate the dispatching of battery load.

The importance of the customer acquisition process cannot be overstated. The Power.House system works best in a specific type of location. The process is not simple as it involves rooftop solar, a fairly large battery and inverter unit, as well as enough space to complete the installation. Synergy North began the customer acquisition process in June of 2017 and the two systems were commissioned in January of 2018. Synergy North was extremely pleased with our customer's engagement and participation throughout the process. As with any field installations, challenges were encountered and the customer was part of overcoming these challenges along the way.

Control and Prediction

The initial designs of the control and prediction systems for the project were rudimentary to ensure the project did not exceed the anticipated budget and timeline. The design and plan changed after a presentation to a local Professional Engineers of Ontario chapter. A group of students and professor from Lakehead University approached Synergy North with a proposal to develop a predictive algorithm which would significantly improve the performance of the system. This change added several extra months to the project timeline but the extra work proved to be rewarding. The partnership resulted in a research paper published in the 2018 International Conference on Computer and Applications (ICCA) proceedings held in Beirut in July 2018. The abstract has been attached as Appendix 1 to this report.

The prediction and rationale is described in the white paper as;

> "*In the … system*, *energy consumption data is a time series data collected every 5 minutes. It gets updated every day and stored for 30 days only. The goal is to predict the next hours using the historical energy consumption readings and weather data since there is correlation with how consumers use their electricity. In this paper, we propose the use of Multivariate Auto Regressive Integrated Average (MARIMA) to perform the prediction [18]. The rational for using MARIMA*

is as follows: First, time series models such as ARIMA are applied with variables measured over time. In our model, we have multiple variables affecting the prediction including, time, energy consumption, temperature, dew point, humidity, wind speed, visibility, pressure, wind chill. These multi variables have varying effect on energy consumption. Second, the model requires that data include persistence readings, otherwise the error get magnified for longer period. In our system the data is captured in fixed intervals and the goal is to forecast for shorter time steps. Furthermore, MARIMA models are useful for data that exhibit non-stationary due to the presence of trend and seasonality in the observations [19]. (Beirut 2018)"

In simpler terms, the prediction algorithm uses the historical consumption at the transmission station and compares the consumption with six different weather determinants. The relationship between these weather determinants and the historical consumption is used to 'train' the algorithm. The algorithm is then updated daily and learns more about the consumption at the transmission station with each update. Using a test data set, the algorithm was able to identify the transmission station peak with 92% accuracy. A simplified logical diagram of the system is shown in Figure 2.

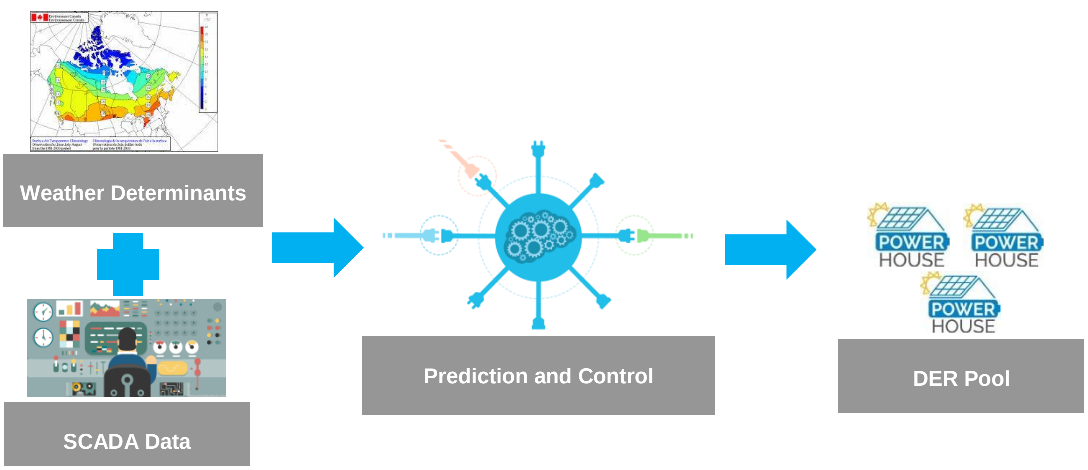

Figure 2 Overview of prediction and control

The control system was developed to receive the prediction from the algorithm and dispatch the DERs accordingly. The control system is a java application which receives a prediction at midnight each day. The system then configures the DERs for dispatch 22 minutes before the predicted peak. The idea is to attempt to span the peak with 45 minutes of sustained load from the DERs. The process flow Diagram is shown below in Figure 3.

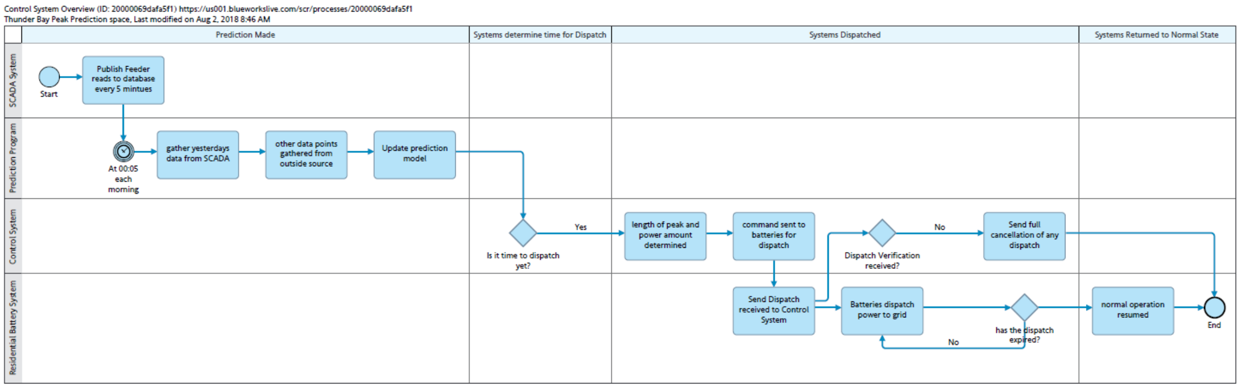

Figure 3 Process Flow Diagram

Project Results

Work plan Results

Phase 1: Install Two More Power.House systems (Completed January 2018)

- Synergy North will select two more houses for Power.House deployment
- Procure/Deliver/Install the Power.House systems

Phase 2: Integrate all 3 existing systems with Synergy North's SCADA system (Completed June 2018)

- Using the API provided by each system
- Using the API provided by the SCADA system

Phase 3: Configure SCADA system to use these systems as dispatchable load when it is needed. (Completed June 2018)

- Leverage all 3 systems to supply congested areas during peak times.

Peak Demand Reduction

The automated process ran smoothly through July 2018 with the appropriate battery dispatches happening on a daily basis. The DERs successfully dispatched approximately 23 kW's during sixteen of the thirty-one daily peaks during the month. One of these sixteen correctly predicted peaks was the highest peak in July. The accuracy of the predictions is shown below in Figure 4. As a result, the daily process of prediction and dispatching the DERs lowered Synergy North's monthly transmission peak by 23 kW's on the test feeder. The transmission cost, which is passed through to customers, was lowered by approximately $125 for the month.

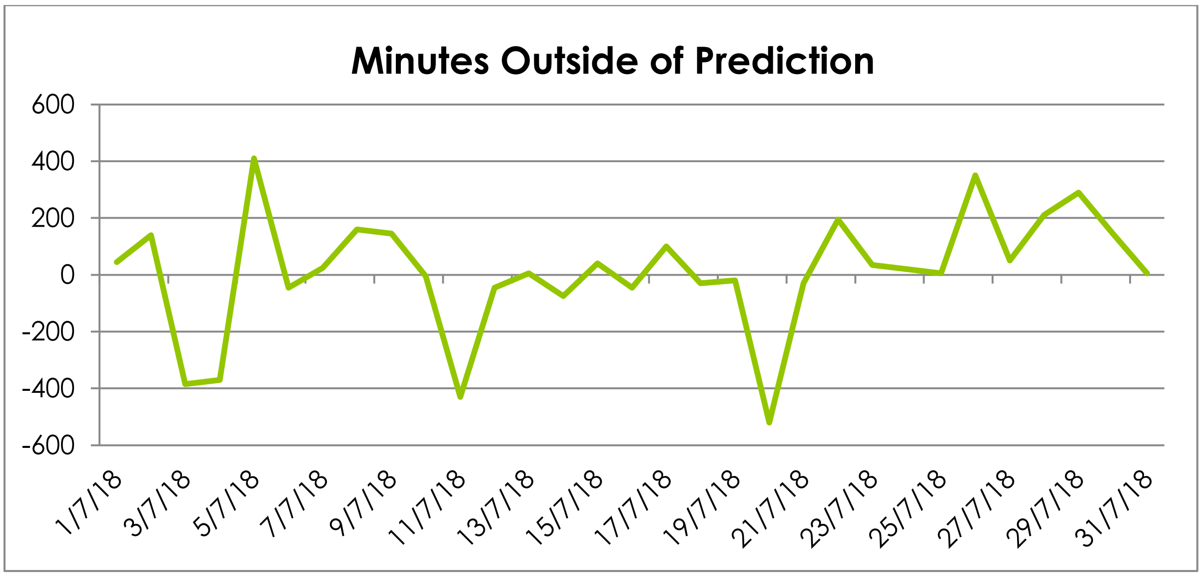

Figure 4 Prediction Accuracy July 2018

Conclusion

Synergy North is pleased with the outcome of the project and will be moving forward to continue to leverage these assets in the field. As a result of the funding, the LDC Tomorrow Fund has helped to foster an innovative path forward for Synergy North and its community partners. Synergy North would like to sincerely thank the LDC Tomorrow Fund for the opportunity to pursue this project.

About Synergy North and Subsidiaries

Synergy North Electricity Distribution Inc. is responsible for the power line system and delivering electricity to the homes and businesses within the city limits of Thunder Bay, Kenora and Fort William First Nation. We build and maintain the local power line system, provide 24-hour emergency response, answer billing questions, provide for the reading of meters, and offer energy conservation advice and programs.

Thunder Bay Hydro Renewable Power Incorporated is a subsidiary whose strategy is to develop renewable energy generation projects in the Thunder Bay area. We own and operate the Mapleward Renewable Generating Station, a methane powered generator.

Thunder Bay Hydro Utility Services Inc. provides back office systems and support, IT hosted applications and program management that includes conservation programs to other electric utilities companies in Northwestern Ontario.

Appendix 1

S. Rinchen, A. Yassine, K. Schwartzentruber, H. Ahmed and A. Armitage, "Integrating Small Scale Green Energy into Smart Grids: Prediction for Peak Load Reduction," 2018 International Conference on Computer and Applications (ICCA), Beirut, 2018, pp. 104-109.

doi: 10.1109/COMAPP.2018.8460222

Abstract: The emerging Smart Grid technologies allow for the integration of clean energy from small-scale energy generators (SEGs). In this paper, we investigate a model by which an electric grid operator (EGOs) schedules the integration of clean energy from residential homes acting as SEGs. These SEGs are equipped with rooftop photovoltaic (PV) and a bank of utility grade battery systems. The challenge facing the electric grid operator (EGO) is that home-based battery systems require several hours of sunlight to charge from rooftop PV panels, and an average 90 minutes to be discharged to 30% original capacity. The EGO must be able to schedule the discharging cycle so that it coincides with the time of the highest peak load during the day for efficient cost reduction. In this paper, we propose a model that allows the EGO to predict the highest peak of energy consumption on the distribution feed where the SEGs are connected. For the realization of the system, we have acquired a dataset which includes time series of energy consumption data for approximately 1500 houses including 3 SEGs. We performed our prediction using the multivariate autoregressive integrated moving average (MARIMA) method and achieved 92.64% accuracy. The real-life implementation of the system and the prediction model are described in this paper.

URL:
http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=8460222&isnumber=8460181