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Demand Response Implementation for Remote Communities

Installation Challenges and Initial Results for the Village of Hartley Bay

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***Abstract*— A demand response system has been installed in the Village of Hartley Bay, a remote community in BC, Canada, with the intent improving overall general dispatch efficiency. This community of 170 people is supplied by a small electrical network that is powered by three diesel generators. The demand response system is being developed to shed or add demand when a predictive algorithm, "the typical curve," estimates an inefficient peak is to occur. Variable thermostats and 30 amp load controllers were installed in the commercial facilities to shed loads in, e.g., the school, health center, and community center. The total shed capacity is 20 percent of the typical maximum winter demand. Initial results indicate an unnoticed change in level of service to the community and an unexpected benefit of energy conservation with limited rebound and an anticipated energy reduction of up to 3 per cent.**

Index Terms – Smart Grids, Energy Conservation, Demand Response; Implementation Challenges; Energy Management; Energy Control

I. INTRODUCTION

Volatile and high fuel costs and environmental issues from diesel fuel are a significant concern in isolated communities [1]. Electricity costs can be many times that of utility connected systems due to economies of scale and fuel transportation costs [2]; therefore, small improvements in efficiency of the community power system can have significant economic benefits. It is paramount for the utility system operator to find new and innovative ways of optimizing the system operational costs. One of the options for improving the system efficiency is to use a demand response system to prevent operational inefficient states. A smart meter infrastructure can then be used to verify the benefits [3], [4]. Demand response is a type of demand side management used to reduced power system congestion and to increase overall system efficiency [5] by shedding or starting non-critical loads at specific times. The FERC defines demand response as "Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."[6]

This paper highlights some of the planning, benefits, challenges and results of installing such a demand response system in the Village of Hartley Bay. The objective of DR installation is to improve overall electrical generator dispatch efficiency by shedding loads during certain peak demand events.

A. Community Description

Hartley Bay is a remote coastal community in the Gitga'at Nation located 650 km Northwest of Vancouver, BC. The community is engaged in an innovative energy management program that aims to reduce the amount of energy it consumes and the GHGs it produces. One area of focus of their energy management plan is to improve the management of assets including the optimization of diesel generator dispatch strategies and synchronizing generator schedules with demand requirements based on system efficiencies. Other programs have included installing smart meters, retrofitting homes and commercial buildings with improved lighting, heating, and HVAC systems and hiring energy coordinators to locally manage and engage the community. The community owns and runs their own utilities including the electrical system.

II. PURPOSE OF DEMAND RESPONSE IN HARTLEY BAY

There are three generators supplying the electricity to Hartley Bay: two are 420 kW and one is 210 kW. A 900 kW, twin turbine, small storage, run-of-river hydro electric project is planned to begin construction in 2012. A generalized single line diagram of the electrical system is given in Figure 1. The system consists of a 600V bus at the generators which is stepped up to 25kV for distribution (approximately 2 km of lines) and stepped down to 120/240/208V for residential and commercial single and three phase loads with 25kVA and 50KVA transformers. The community has historically used up to 2 GWh of electric energy annually at a levelized cost of production of approximately $0.67 per kWh. The efficiencies of the diesel generators have been measured for over a year by installing real-time fuel flow sensors on each of the three generators and an electrical power meter on the main bus. The resolution of measurements is one sample per minute. The efficiency of the two 420 kW generators are very similar and they significantly out-perform the 210 kW generator's efficiency (Figure 2). The poor performance of the 210 kW generator was unexpected. Further analysis of the 210 kW generator found that it is mechanically governed whereas the 420 kW generators are electronically governed, contributing to the difference. The efficiency of the two 420 kW generators is nearly flat across its power spectrum at 0.27 l/kWh and begins to roll off at powers less than 33% of the rated maximum whereas the 210 kW generator has a very steep efficiency curve averaging around 0.60 l/kWh. It is clear that the 210 kW generator's operation should be avoided whenever possible. The two cases when the 210 kW generator, "G1", is running is during low demand states and during high demand states. A higher efficiency can be gained by adjusting the generator dispatch set points to avoid the operation of the 210 kW generator.

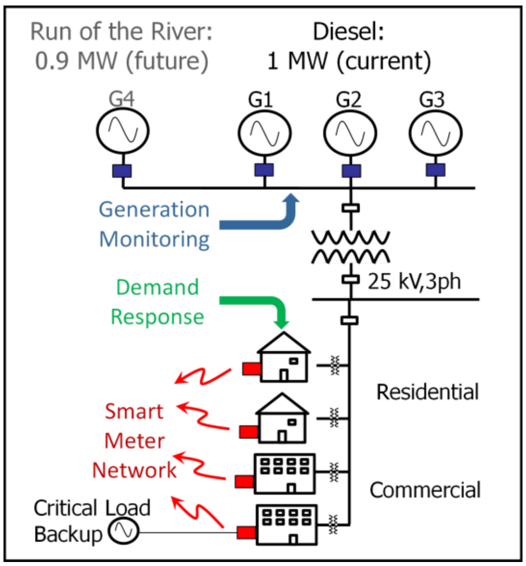

Figure 1: Power System in Hartley Bay

Furthermore, demand response can be used to avoid loading when the 210 kW generator must be run. Each day has demand peaks and troughs. Demands above 340 kW result in dispatching the 210 kW and the 420 kW generators in parallel (Figure 3). The peaks can be avoided by shedding or shifting the demand times using a demand response system.

III. Load Control for Demand Response

Choosing the right loads to shed is as important as having the capacity to shed demand [7]. Controllable loads chosen must not affect the comfort or safety of the occupant or building while the load controller devices must have the capacity to be practically installed [8]. For Hartley Bay, this required a careful analysis of the community demand profiles using the installed smart meter infrastructure to develop a detailed energy budget of the highest consuming facilities in the community and then inspecting the facilities to determine what the impact of a DR program would be. The top seven highest electrical energy consumers in the community are the health center, school, gymnasium, cultural center, wharf, band office and water treatment plant. A further more detailed audit of these facilities revealed that the loads with the highest energy usage with the least occupant disturbance are baseboard heaters, hot water heaters, HVAC systems, and flood lights. After discussion with the building operators, it was determined that these loads can be modulated with little to no occupant discomfort but an option to "opt out" must be available. Two of the buildings' HVAC systems are operated by building automation controllers, the health center is 100 percent heated by electricity and the gymnasium has a very large hot water heating system. The variety of building construction styles in the community made choosing a generic installation solution challenging. For example, thermostats could be low voltage 2 wire, 3 wire powered, 4 wire, analog line voltage or building automation computerized control. The thermostats chosen for this program are powered 3 to 4 wire devices for basic HVAC control with an option to expand for heat pump and multi-stage systems.

The variety in systems also limited the speed at which the installation could occur. There were 20 controllable thermostats installed and 12 load controllers installed. The initial goal was to install thirty of each but due to the

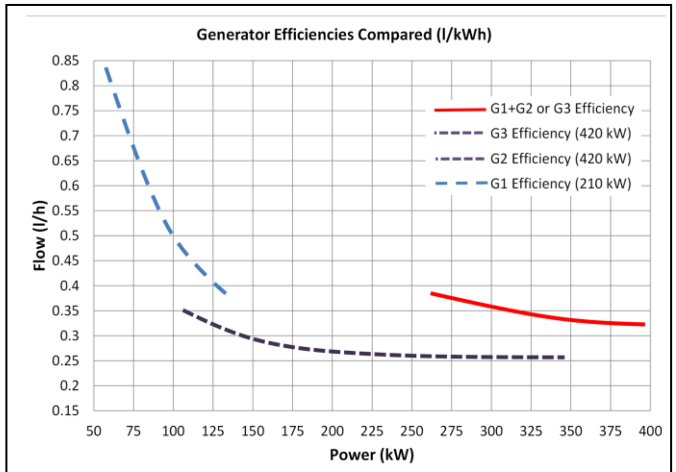

Figure 2: Generator Efficiencies

significant variability of control technologies installed in the community over the years, not all thermostats could be replaced and not all HVAC systems could be safely interfaced. The total control of loads total 61.3 kW, or approximately 15 to 20 percent of the average maximum daily demand (Table 1). Peak demand typically occurs three times per day: 7:45 AM, 12:30 PM, and 5:00 PM (Figure 3) with the 5:00 PM peak usually being the highest.

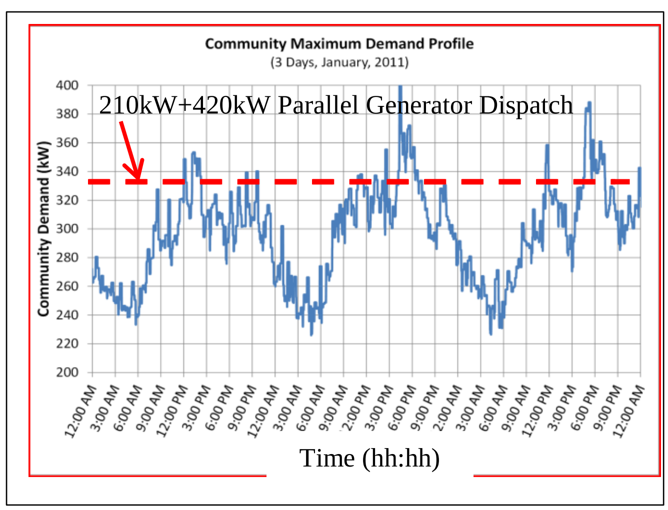

Figure 3: Community Winter Demand Profile over 3 Days

Demand response of the selected loads requires the use of either a remote controllable thermostat or a direct control power switch. Cooper Power Systems wireless demand response control thermostats and 30 amp load control switches are used for the hardware load controls and the dispatching of demand response decisions is being developed by Pulse Energy. The low voltage thermostats are designed to be a simple retrofit for existing HVAC and heat pump systems but pose a challenge for line voltage controlled baseboard heaters: the baseboard heaters can only be controlled with the thermostats using a low voltage, high current light control relay inserted in-line with the thermostat and the baseboard heaters. The hot water tanks and lights have the 30 amp direct load controllers placed in-line with their circuits. To manage potential problems with customer dissatisfaction or field failures, bypass switches have been installed in-line or in parallel with the load controllers. The thermostats are off the shelf low voltage items and considered low risk for field failures as they can be quickly swapped out if needed.

Table 1: Types of Loads Controlled

Sum of Estimated Demand Under DR Control (kW)	
Load Type	Total (kW)
Baseboard Heat	7
Hot Water	17
HVAC	36.5
Flood Light	0.8
Grand Total	61.3

IV. Demand Response System Architecture

The complete system is being developed to operate using a four layered control hierarchy (Figure 4). The top layer is the environmental decision maker that takes external variables into consideration and decides if and when to trigger a demand response call. The next layer is the controls and operations layer which sends commands to specific equipment such as temperature settings and shed time for the thermostats, hot water heaters, or HVAC systems. The third layer is a physical control layer that takes the second layer's commands and sends messaging out over a wireless network. The final layer is the actual physical device layer which is receiving the specific commands and decides on the specific moment it will turn on or turn off. The on and off function of the demand response controllers is random over a 15 minute period to prevent undesirable spiking and dropout.

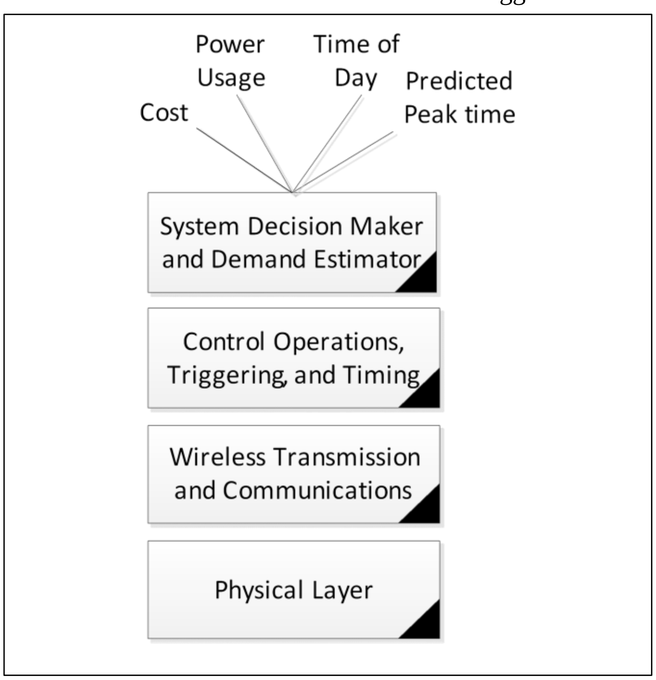

Figure 4: System Control Hierarchy

The system decision maker is being designed to use a demand estimation tool, "the typical curve," to follow the demand, estimate peaks, and trigger a "shed" period of up to 30 min to avoid a specific peak. The typical curve is a predictive tool included in the Pulse Energy Management software system suite of analysis tools that takes the past demand history and weather to estimate the demand curve for the next few hours. The typical curve requires six months to a year to "learn" the community's behavior. Sustained high demand periods are disregarded for demand response functions.

Communications between the architectural layers are allowed to be intermittent as each layer can manage its own state after a command is initiated. Load controllers and thermostats can operate independently once a command is received and require no further feedback. Recovery from power outages are managed by the physical layer: individual loads are randomly returned to normal operation over a 15 minute period following recovery from an outage. Thus, the DR architecture not only is used for demand response, but also for reducing the community black-start demand peaks.

V. Initial Results

At present, all layers for the system control hierarchy have been fully implemented except for the linkage between the *System Decision Maker and Demand Estimator* and the *Control Operations, Triggering, and Timing* layers (Figure 4). To initiate demand response signals, demand curves are observed visually by the operator in real-time and shed by manually triggering the control operations layer (web based) to initiate a load shed.

The implementation of the demand response system resulted in an unintended, but positive, outcome: conservation. This was unexpected as demand response is generally thought as a load shifting technique, i.e., total energy used should remain unchanged. Examine Figure 5, which represents power consumption for a typical day in the gymnasium. The three 10 kW spikes are from the hot water heater elements switching on and off and the steady state demand is from the HVAC ventilation; both these loads are connected to the demand response system. When the demand response event occurred (in the unoccupied gymnasium), the demand dropped, as intended, over the 10 minute period of the event. However, after restoration, the loads reacted differently. Once power was restored, the elements of the hot water tank immediately turned on, creating a spike slightly longer than what would otherwise occurred as the tank made up for 'lost time.' However, the ventilation system continued to operate with no change (i.e. increase in power use). Thus, this demand response event brought a net benefit of conservation via the ventilation system. (Net energy use from the hot water tank will have remained constant.)

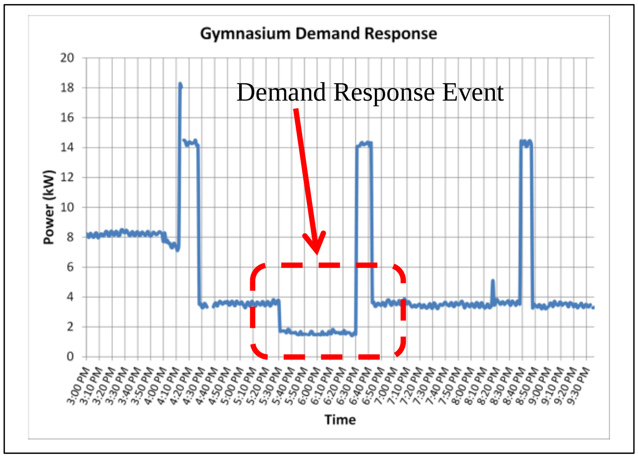

Figure 5: Gymnasium Demand Response with Rebound

Further extending the observation to a community wide view, two days have been compared. More specifically, the day the DR occurred and a three day average composed of the previous two days and the following day from the month of June, 2011 (Figure 6). (These days had similar temperature profiles.) One day has a demand response event in the morning (dark blue line) and another does not (light grey line). The demand response event occurred at 7:36AM for 30 minutes. The reduction in demand was approximately 45kW (Figure 6). This day was chosen as a demonstration but the real benefit of preventing dispatching generators must wait until the fall of this year when the higher demands begin dispatching two

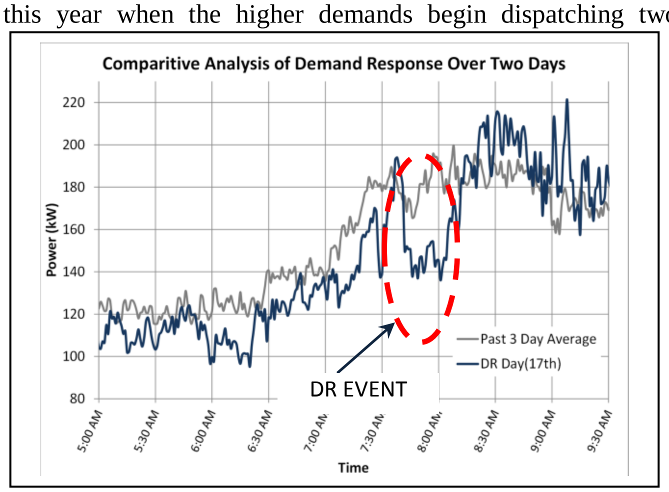

Figure 6: Demand Response Comparison for Similar Days with and without Demand Response

generators to work in parallel.

VI. Next Steps

There are several steps to be completed under this project. First, it must be run in the winter. The demand response system was installed in the spring whereas winter loads (with high peaks) are the primary control target and will be needed in order to effectively demonstrate the system's benefit of an anticipated fuel reduction of up to 3 percent. Second, the demand response system will be setup so that loads will not trigger the 200 kW generator (which is hugely inefficient). To achieve this, freezers will be used to store energy. The community uses many large freezers to store their food and the concept of "super cooling" to store energy is being designed for installation where many freezers will be deliberately enabled simultaneously at low demand times. Finally, integration with the load estimator, to automate the demand response dispatching, is to be completed this year.

VII. Acknowledgment

This research would not have been possible without the support from Pulse Energy Inc., CanmetENERGY, Government of Canada, through the Program on Energy Research and Development; Sustainable Development Technology Canada (STDC); the Innovative Clean Energy Fund (ICE); and the Gitga'at Nation from the Village of Hartley Bay. We would like to particularly thank David Benton, the Manager of Special Projects from Hartley Bay, for his continual dedication and vision towards clean energy program at Hartley Bay and Bruce Cullen, the Remote Communities Manager from Pulse Energy, for his leadership that maintains the momentum of the program.

VIII. Refereces

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IX. Biographies

Michael C Wrinch (M'01) Received his B.A.Sc. degree in 2000 and M.A.Sc. degree from Memorial University of Newfoundland, Canada and his PhD from the University of British Columbia where he specialized in power system island detection. His research interests lie in emerging energy systems integration and real time demand data intelligence. He is an active member of the IEEE and he is a Professional Engineer in the province of British Columbia, Canada. Michael is currently a retained Consultant for Pulse Energy Inc. and owns Hedgehog Technologies Inc., an engineering consultancy company.

Steven Wong (S'05-M'10) is a T&D Research Engineer with the Grid Integration of Renewable and Distributed Energy Resources Group at CanmetENERGY, Natural Resources Canada. He obtained a PhD in Electrical Engineering from the University of Waterloo, Canada, in 2009. His research background and interests lie in power system planning, including distributed generation, distribution and transmission systems, sustainable energy resources and storage, and innovative energy markets.He is currently working in the areas of smart grid development and photovoltaic system integration.

Tarek H. M. El-Fouly (S'97-M'07) received the B.Sc. and M.Sc. degrees in electrical engineering from Ain Shams University, Cairo, Egypt, in 1996 and 2002, respectively. He received the Ph.D. degree in electrical engineering from the University of Waterloo, Waterloo, ON, Canada, in 2008. He joined CanmetENERGY, Natural Resources Canada, in 2008, as a Transmission and Distribution Research Engineer where he is conducting and managing research activities related to active distribution networks, microgrids, and remote communities. His research interests includes protection and coordination studies, integration of renewable energy resources, smart microgrid, smart remote community applications, and demand side management and forecasting.