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## **BC Hydro Perspective on Distribution Islanding for Customer Reliability Improvement**

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### **SUMMARY**

BC Hydro, one of the largest electrical utilities in Canada, has experienced a substantial growth in distributed generating sources that are connected to its distribution system (12 kV, 25 kV and 34.5 kV). These Power Generators (PGs) are mostly run-of-river hydraulic generating plants with capacities ranging from 1.0 to 15.0 MW. This increment in the number of independent power producers (IPPs) is the result of an aggressive energy acquisition plan to meet provincial renewable energy targets.

Introducing small PGs into the distribution system, however, is changing the way how the distribution system is planned, operated and protected. New technical, economical, and environmental challenges are coming up and they must be properly addressed to avoid jeopardizing system operation and customer reliability. BC Hydro has developed technical interconnection requirements guideline [1] for various types of PGs connecting to its distribution system. BC Hydro's current practice is to avoid non-intentional islanding operation by de-energizing all distributed generators without islanding capabilities whenever the feeder circuit breaker opens to avoid a potential detriment in power quality. This can be achieved by implementing a transfer trip signal or by means of power quality (voltage and frequency) protection relays.

Improving reliability in locations where reliability is below the customer expectations is one of the top objectives BC Hydro constantly endeavors to achieve, and was the main driver for BC Hydro to explore distribution generation islanding as one of the feasible solutions to improve power supply reliability. Given the amount of technical considerations to be taken into account when a generator operates islanded from the system, BC Hydro decided to take the lead on this issue and release a Distribution Power Generator Islanding Guideline [2] intended to provide existing and new generators with the technical requirements, considerations, and procedures to implement a planned islanded operation.

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This paper presents the BC Hydro's perspective on distribution islanding and assesses its impact on customer reliability performance. It starts in Section 2 with a description of the major technical considerations according to the BC Hydro generator guideline for distribution planned islanding, which covers equipment islanding capability of voltage and frequency regulation, generator black start, dead load pick-up, protection coordination, transient overvoltages, and operational and safety issues. Section 3 provides an insight on the impact of planned islanding on customer based reliability, which is the approach BC Hydro utilizes to assess reliability to its customers. The strategies followed by BC Hydro for planned islanding are outlined on Section 4. Finally, a recent successful experience on intentional distribution islanding implemented in one of the BC Hydro substations is presented in Section 5.

## **KEYWORDS**

Distribution system – Islanding – Power Generator – Interconnection Requirements – Distributed Generation – Reliability.

## **1. INTRODUCTION**

IPPs emerged years ago in the province of British Columbia allowing various distributed PGs to be connected to the BC Hydro primary distribution system. Given the importance of having small distributed generators with islanding capabilities and its impact on customer reliability enhancement, BC Hydro developed distribution intentional or planned islanding guideline for PGs connected to its distribution system. This article presents the BC Hydro perspective and strategy on distribution islanding and assesses its impact on customer reliability performance. BC Hydro distribution islanding guidelines and strategies are outlined, and a successful planned islanding project resulting in customer reliability improvement is presented.

## **2. DISTRIBUTION ISLANDING GUIDELINES**

BC Hydro has set up distribution islanding technical criteria for existing and new PGs that are to be connected to the distribution system at voltage levels of 35 kV and below. These considerations focusing on planned or intentional islanding are discussed in this section.

### **2.1 Distribution Equipment Rating**

The BC Hydro distribution system comprises overhead and underground equipments operated at 35 kV and below which extends from the substations to the customer load and PGs. Current BC Hydro distribution design limits the size of PGs to about 17 MVA at 25 kV. Thermal capacity on primary feeder conductors or cables, in addition to the voltage regulation along the feeder, is verified before integrating a PG. Feeder voltage regulators are retrofitted or replaced by units with reverse power sensing and tap-changing to account for bi-directional power flow allowing voltage control in both forward and backward direction which may be required in cases when an island operating condition reverses the power flows in the feeder. As fault currents may increase the required interrupting capabilities of fuses, reclosers and sectionalizers, a review of these ratings is also needed. Single-phase hydraulic-controlled line reclosers having low interrupting rating may be replaced by three-phase electronically-controlled reclosers. A recloser may be also used to replace line fuses that will not fully coordinate with the main substation feeder protection.

### **2.2 Generator Islanding Capability**

BC Hydro has developed a “two-to-one” rule-of-thumb [3] to assess whether a PG can inadvertently hold an island with a feeder load, or a complete distribution substation load. This rule is based on the assumption that an island is not sustainable where the annual minimum load in the island is at least twice the island’s maximum generation capacity. In other words, in the event that a PG forms an island with a load of twice its capacity, the generator power quality protections will trip off the main generator breaker. The “two-to-one” rule-of-thumb is sufficient to determine whether further substation and/or transmission technical studies are required to interconnect a PG and also to assess its islanding capabilities.

### **2.3 Generator Ride-through and Load Pick-up**

When the substation feeder breaker opens for whatever reason, a transfer trip signal to the PG prime mover controller may be required to initiate a switch from constant power to load-following isochronous control mode to maintain voltage and power flow into the island. The ride-through capability of a PG to pick up and sustain the load in a feeder under a loss of the main utility source will generate an islanding condition. Technical studies are required to avoid power quality, safety and out-of-step reconnection issues in the islanded system.

There will be cases where the PG will not successfully maintain the island due to the nature of the disturbance and the voltage and frequency excursions that may be present immediately after the island occurs. In this case, the PG must be equipped with a direct means of voice communication between

the Control Centre and the PG, have black start capability to re-start while the utility source is unavailable, and have appropriate controls, governor, exciter, and inertia to pick up and hold dead feeder load. Should the PG be incapable of supplying the total load of the feeder during islanding operation, load shedding or feeder sectionalizing is required. System load shedding is usually done by automatic or supervisory control following selected breaker trips. However, high speed load shedding is difficult to achieve on distribution feeders where customers are typically connected through fused cutouts or other disconnecting devices that do not have supervisory control. In order to sustain feeder islanded operation, manual switching to disconnect customers and/or customers load curtailment may be required. Fully automated or remotely controlled switching could be used increasing the system upgrade costs, but at the same time, reducing restoration time and improving feeder reliability performance.

## **2.4 Protection Coordination**

PG overcurrent protection relays need to have bi-directional overcurrent elements and be capable of switching settings from parallel to islanded operation which could be initiated by a feeder breaker opening signal. Voltage and frequency requirements at the PG terminal may be different for parallel and islanded operations as the latter is considered as a temporary emergency condition. Therefore, limits and settings for over/under voltage and frequency might be changed from one state to the other. Substation feeder breaker must be equipped with a synchronism check relay to avoid out-of-synchronism breaker closing. Voltage supervision shall be provided via voltage transformers installed at both (source and load) sides of the substation feeder breaker. Reclosers installed between the PG and the substation or source must have its reclosing capability disabled to avoid out-of-synchronism closing. Fuses connected in series between the substation and the PG shall be removed from the system, relocated or replaced by switches to avoid miscoordination. Finally, a PG operating in parallel with the system or with another generator may go out-of-step and swing against each other under certain perturbations requiring for an out-of-step protection relay at the PG intertie protection. If the swing centre is located on the feeder, then out-of-step relay shall be located at the substation feeder breaker, in which case the breaker must be rated for out-of-step trip duty to withhold potentials transient recovery voltages.

## **2.5 Transient Overvoltages and Transfer-trip Signal**

When a PG is connected via a feeder supplied from a distribution substation transformer that is high-voltage side ungrounded or delta-connected (BC Hydro Standard), a line-to-ground fault on the transmission line and the trip of the utility remote transmission breaker can raise voltages on the healthy phases of the transmission line serving the distribution substation.

These over-voltages can be much higher than line-to-line level when the PG becomes the only source back-feeding into a line-to-ground fault on an ungrounded transmission system. This line-to-ground fault on the transmission system will trip the utility remote transmission line breaker only since there is no zero sequence current contribution from the PG to the fault due to the delta-connected high-side of the distribution station transformer. Over-voltages on the healthy phases for this duration can raise much above line-to-line voltage, if the inductive reactance of the system under weak source condition exhibits low frequency series resonance with zero sequence line capacitance of the transmission line. Transfer trip signal from a remote transmission breaker to the substation feeder breaker where the PG is connected is required to avoid unacceptable temporary overvoltages during the clearing of line-to-ground transmission faults.

## **2.6 Operation and Control**

PGs having ratings from 1 to 10 MVA are required to provide operating data (MW, MVA<sub>r</sub>, MWh and kV) and interconnection status (open/closed) to the Control Centre. This is usually done using dial-up data communication to Intelligent Electronic Device (IED) with DNP 3.0 communication protocol. Similar data is required for PG ratings over 10 MVA in addition to unit connection status and unit running status.

In a normal non-islanded operation condition, the utility grid system stiffness generally ensures that frequency and voltage to customers is controlled and maintained within power quality limits. However, the stability provided by the system is lost when the feeder becomes an island supplied only by the PG which, nevertheless, is required to continue maintaining the steady-state voltage and frequency limits defined by the BC Hydro's interconnection requirements guideline [1].

For a planned islanding interconnection, there are additional operating interface features that are necessary to ensure appropriate operation and customer power quality. To ensure quick operation reaction, the status and data link needs to be real-time continuous over a dedicated telephone leased line or equal and PG frequency and current are also required in addition to MW, MVar, kV, MWh, and PG interconnection breaker open/close status. For an unforeseen event where power quality deteriorates continuously outside acceptable limits, a direct means for the Control Centre to trip the PG breaker should be considered to avoid or minimize damage to BC Hydro customers within the feeder island. In order to avoid an unnecessary customer outage when the BC Hydro substation recovers and is ready to be connected to the feeder, auto-synchronization initiated by the Control Centre to parallel the island via the substation feeder breaker may be warranted.

Distribution control centre dispatchers and lineman crew require additional training regarding the operation of the PG in island during transmission or substation outages. If dead line work is to be done on the feeder, the substation and the PG need to be isolated from the feeder. The line between the substation and the PG must be under Control Centre direct control, meaning that our self protection rules cannot be used.

## **2.7 System Impact and Facility Studies**

Dynamic and steady-state studies must be performed to ensure the operation in island of a feeder with a PG is technically feasible. Typical studies to be conducted are unbalanced load-flow, short-circuits, transient and dynamic stability, and electromagnetic transient studies. Motor-start studies should be performed when large motors are expected to be part of the island under study in order to verify that inrush currents and voltage dips will be withstood by the generator during islanding operation. The results and recommendation of the system studies mentioned above are gathered and put together in the impact or feasibility study report. Facility or design studies will collect the scope of the work required to implement an islanding project. Distribution system upgrades and all additional improvements required at the substation and the PG plant will form part of the Project Interconnection Requirements (PIR) report prepared as a result of the facility study.

## **3. PLANNING FOR CUSTOMER RELIABILITY**

The current BC Hydro mandate for managing the delivery of reliable service to customers is as follows:

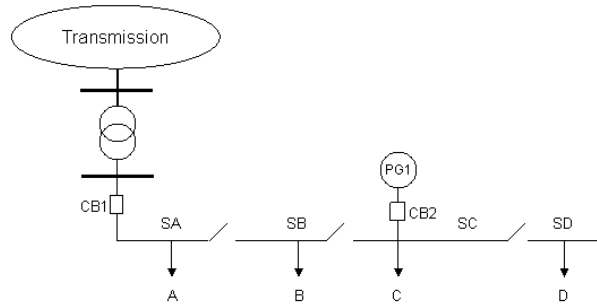
- To maintain reasonable and acceptable levels of reliability for customers, communities and the rate base as a whole.
- To meet performance objectives defined in the BC Hydro Service Plan, as filed with the shareholder and with the regulator.

In order to measure and assess reliability performance, BC Hydro computes a series of indices per feeder and customer level in a monthly basis as it is done by many other utilities. However, in addition to this traditional approach a different mechanism called Customer Based Reliability (CBR) has been implemented at BC Hydro intended to measure customer reliability in the distribution system. CBR approach imbeds the reliability needs and expectations of BC Hydro's customers in the asset management decisions of the company. It focuses on customer needs and initiates improvements where the system reliability does not meet customer expectations.

### 3.1 Impact of Distributed Generation on Reliability

Distributed generation connected to distribution systems and its impact on customer reliability has already been addressed and indices calculation methodologies proposed in a few publications [4]-[6]. Most authors agree in that significant performance reliability improvements can be achieved when PGs with islanding capabilities are connected to the distribution system. Even though interruption frequency based indices such as SAIFI may be increased or decreased depending on the islanding strategy, switching devices and system automation available, interruption duration based indices such as SAIDI or CAIDI may be significantly improved.

Figure 1 shows an example of a distribution system having one PG with islanding capabilities connected to a feeder. There exist four different islands that may be formed in this system depending on the location of permanent faults and the islanding capability of PG1. If a fault occurs in the transmission system, PG1 might form an island for instance with loads A, B, C and D after CB1 is open. Permanent faults along the distribution feeder will allow PG1 to form islands with either loads BCD, BC, CD or with load C solely reducing the number of interrupted customers along this feeder. Without islanding capabilities at PG1, a fault in the transmission system will cause an outage to all the customers connected to the distribution system.



**Figure 1 Typical Distribution system including a PG**

As an example, let consider the calculation of the index SAIDI to be as follows:

$$SAIDI = \frac{\sum_{i=1}^n r_i N_i}{NT} \quad (1)$$

Where  $r_i$  is the outage or total restoration time for each interruption  $i$  and  $NT$  the total number of customer served in the system. These two parameters are not dependent on the number of PGs connected in the system or whether these PGs have islanding capabilities or not. Whereas  $N_i$ , which is the number of customers interrupted per each outage  $i$ , can be significantly reduced by having PGs with islanding capabilities, which in turn, will reduce the value of SAIDI. If the number of interruptions  $n$  is not increased by the island formation, SAIFI and CAIDI indices might be reduced as well. Theoretical tests have shown that the further from the station a PG is located, the higher is the level of reliability obtained. In addition, smaller capacity PGs shall be installed at the upstream side of PGs with larger capacity [5]. These findings might be used for planning and design purposes in distribution systems including disperse generation, but with certain caution since having generators located in remote areas may increase not only interconnection costs, but also the islanding enabling capabilities costs.

## 4. BC HYDRO ISLANDING STRATEGIES

Planned islanding strategies, either ride-through or black-start, can be implemented in distribution systems. Ride-through planned islanding means the PG can ride through the disturbance and maintain continuous supply to the feeder load without interruptions; whereas black-start planned islanding

means the PG cannot ride-through the disturbance and an outage will be experienced by the feeder load before the PG black-starts, picks up the feeder load, and restores the power supply to the island. Special considerations should be taken when choosing either strategy. BC Hydro has been successful in implementing both strategies in different locations of its distribution system. Main issues and selecting criteria are described in this section.

#### **4.1 Ride-through Planned Islanding**

The choice of implementing a ride-through versus a black-start planned islanding strategy depends on the capabilities of a PG to ride through load variations while keeping the system safe and maintaining an acceptable power quality in the island. Ride-through planned islanding will highly depend on the type of sources used by the PG and its availability and security of supply during the whole year. PGs with firm energy and capacity such as thermal and reservoir hydro plant are good candidates for both ride-through and black-start planned islanding. Transfer trip signal coming from the substation circuit breaker is required to switch generator control from constant power to fix-frequency (isochronous) mode and to change protection settings. Sync check at the feeder breaker to avoid out-of-step reclosing, automatic voltage regulator to control system voltage, and excitation system capable to provide sufficient voltage field to boost fault currents along with black start capabilities are required. Proper protection coordination along the feeder, network equipment upgrades (recloser, fuses, and switching devices), and real time telemetry are also needed.

Boston Bar Hydro is a 8.6 MVA run-of-river PG connected to the BC Hydro distribution system that has been in service for more than 10 years [7]. This PG might operate under a ride-through planned islanding strategy as long as it has enough water to generate. If the PG cannot ride-through a disturbance to supply the islanded load, it will switch to a black-start planned islanding operation. Ride-through planned islanding strategy may significantly increase the project cost; therefore a cost-benefit assessment should be performed in addition to the technical feasibility to ensure that reliability performance improvement will exceed the cost of implementing the islanding project.

#### **4.2 Black-start Planned Islanding**

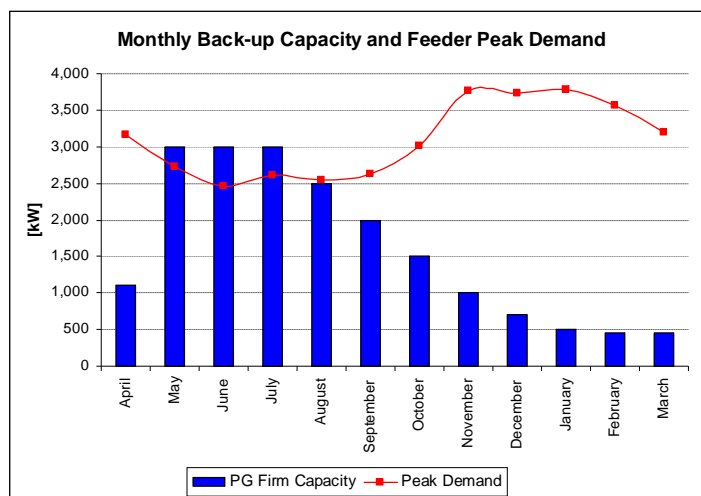
Black-start planned islanding is less costly in terms of capital cost and is easier to implement compared to ride-through planned islanding. Black start and cold load pick-up capabilities, double sets of protection settings, automatic voltage regulation, and constant frequency (or speed) control mode are required at the generator level. At the distribution system level, voltage supervision at the station feeder relay and feeder switching equipments upgrades shall be implemented. Although black-start planned islanding might be less expensive in terms of capital costs, it will have higher operational costs as all switching operations will be most likely performed manually by field crews. Switching devices could be remotely controlled from control centre to avoid manual operations, but the cost may be significantly increased. Manual operations might raise safety issues which must be properly addressed in Distribution Operating Orders (DOO).

In addition to increasing the operational costs, reliability performance improvement of black-start planned islanding will be less due to the longer restoration time required by field crews to bring the system on- and off-line. The islanding strategy for a PG connected to the distribution system depends on many factors as mentioned above, and the decision of selecting the most suitable technical and economical alternative shall be carefully studied in a case-by-case basis considering both capital and operational costs, safety and the potential customer based reliability improvement. A black-start planned islanding project implemented a few years ago by BC Hydro in one of the rural substations in the South Interior area of British Columbia is described in the next section.

### **5. BC HYDRO PLANNED ISLANDING EXPERIENCE**

The year 2007, BC Hydro worked out an agreement with a 2x3.6 MVA independent PG to provide back-up emergency power to one of its feeders during transmission or substation outages (source

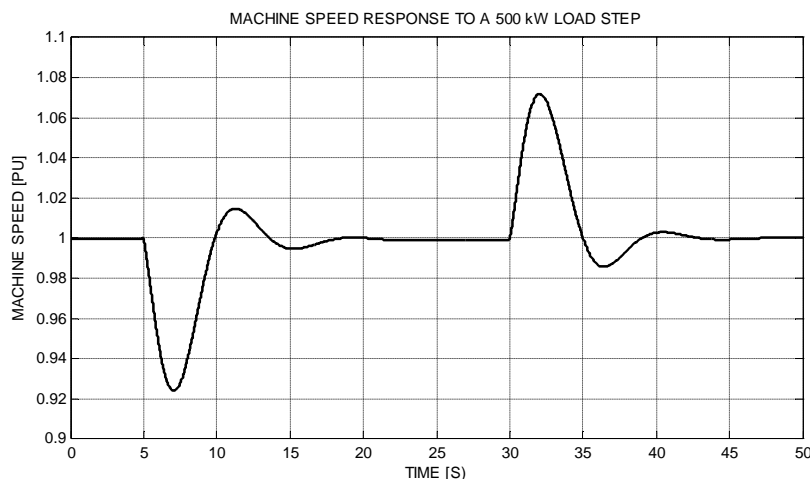
outages) lasting more than 6 hours. The PG is able to supply back up capacity from May to September to rural communities with a peak load of up to 3.0 MW as shown in figure 2. The feeder is manually switched to allow balancing the load with the maximum generation output available at the moment of the outage. Source failures that may last longer than 6 six hours are expect to occur twice a year based on historical outage records in this area.



**Figure 2 Capacity available by the PG and monthly peak demand**

### 5.1 Islanding Requirements and Tests

The PG has load-following capability which is provided by an electronic speed control governor. Black-start power supply is provided via an inverted-based batteries set. Cold load peak-up is estimated in 1.0 MW; however, load pick-up tests have indicated that 500 kW is the maximum initial load that the generator can pick up with an initial frequency of 60 Hz. If the initial frequency is set to 63 Hz, the maximum initial load may be increased to 800 kW allowing a momentary frequency drop to 56 Hz. Pick-up and load rejection tests were performed with a 1,700 kW load bank. The frequency dynamic response of the PG simulated with a time-domain software for a 25 sec. long 500 kW load step is plotted in figure 3. It can be observed that when a 500 kW load step is applied the frequency falls to 55.4 Hz (or 0.924 in p.u.), and then stabilizes after approximately 13 seconds.



**Figure 3 Frequency response of PG to 500 kW load step application and removal**

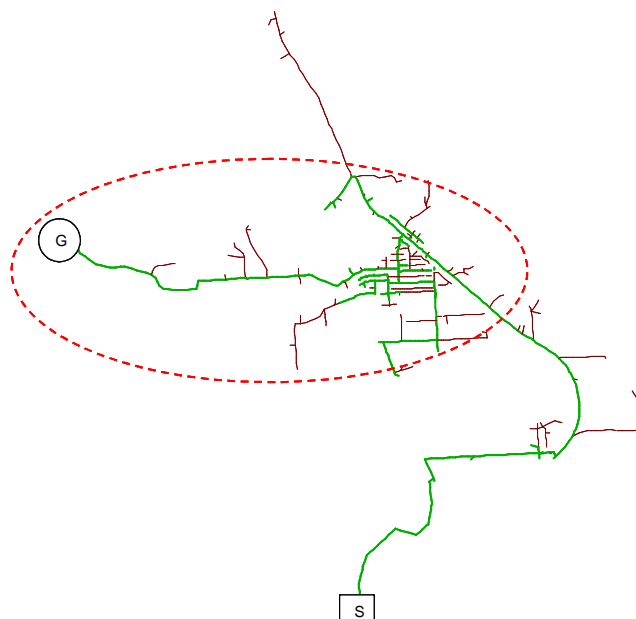
The generator exciter is equipped with an automatic voltage regulator (AVR) which is capable of maintaining the generator terminal voltage within a range of  $\pm 6\%$  of the nominal voltages after a load step of 500 kW is applied. Since there is no automatic transfer trip signal in place, protection settings



(overcurrent, voltage and frequency) must be changed from parallel to islanding operation which can be done either manually or remotely on-line via internet. The distribution feeder had some cutouts fuses with solid blades that were replaced by three-phase gang operated load break switches to allow sectionalizing the feeder and providing suitable load blocks to proceed with a smooth load pick-up, and also to avoid single-phase operation which might trip the generator for current unbalance. The substation was equipped with voltage supervision at the feeder breaker to avoid reconnection under an out-of-synchronism condition, and also with a transfer trip signal for faults in the transmission system. The PG provides to BC Hydro Control Centre remote monitoring of the status of its circuit telemetry data (MW, MVar, MWh, and kV) every 3-minutes via a dial-up IED/RTU with DNP 3.0 communication protocol.

## 5.2 Islanding Operation

Once a transmission or substation fault occurs, an opening transfer trip signal is sent to the substation feeder breaker. Then, power quality protections consisting of under/over voltage and frequency will trip the PG entrance breaker allowing initiating the black-start islanding sequence. The switching sequence to pick-up the feeder load is performed manually by BC Hydro field crew in blocks of 800 kW and following a strict procedure that is well described in the Distribution Operating Order. The isolated area, shown in figure 4 by the dotted red circle, has an average load of 3.0 MW and a feeder extension of around 10 km. Both dynamic and steady-state studies showed an acceptable performance in terms of frequency stability and voltage regulation in the isolated system. Switching sequence may involve the utilization of 2-3 field operators simultaneously to minimize the maximum restoration time which is estimated in 1 to 2 hours per outage.



**Figure 4 BC Hydro 25 kV Distribution System**

## 5.3 System Reliability Improvement

Historical data has shown that rural communities in the area nearby BC Hydro substation in figure 4 have experienced transmission outages averaging 7 hour of duration per year during the last 2 years before the islanding plan was implemented. The main reliability performance indices for the last 4 years are listed in table I. Source outages in the feeder shown in figure 4 have contributed in 20-80% to the total SAIDI during the past 4 years.

Since the islanding plan was implemented in 2007, one transmission outage event involving islanding has taken place. The islanding plan was successfully implemented during this outage and approximately 800 rural customers with a load of 1.1 MW at the moment of the fault were able to stay

in service in island for 5 hours. This event is expected to occur twice per year, allowing the PG to provide back-up capacity for around 10 hours during source outages per year.

**Table I Reliability Indices BC Hydro Feeder**

| BC Hydro Feeder | SAIDI | SAIFI | CAIDI |
|-----------------|-------|-------|-------|
| 2008            | 3.77  | 5.05  | 0.75  |
| 2007            | 7.20  | 6.65  | 1.08  |
| 2006            | 34.16 | 8.87  | 3.85  |
| 2005            | 4.30  | 4.06  | 1.06  |

The implementation of the islanding project presented in this paper allowed reducing SAIDI index from 8.5 to 3.8 hours during the year 2008, which is an improvement of 55% in reliability performance for this rural area.

## 6. CONCLUSIONS

This work presents the BC Hydro perspective on distribution islanding for customer reliability improvement. Strategies for ride-through and black-start planned islanding and technical requirements for successful islanding implementation are outlined in this paper. BC Hydro has been pioneer on implementing planned islanding projects in its distribution system. These real life projects have proved that significant reliability performance enhancements can be achieved by setting out proper islanding strategies in distribution systems including distributed generation, especially in remote areas having a weak transmission system supplying the substation and where long source outages may be present.

BC Hydro has developed distribution planned islanding guidelines intended to guide planners and engineers in developing islanding projects. As a result, two successful projects have been already implemented, two are at study stage, and this tendency is expected to increase in the future. Customer based reliability, approach adopted by BC Hydro to assess reliability performance in its distribution system, can be significantly improved by implementing adequate islanding strategies. This has been proved with the actual islanding case presented in this paper which showed that the reliability indices can be improved in more than 50% thanks to the capability of the PG to provide back-up power during transmission outages.

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