Protection & Control Challenges with Distributed Generation

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OBJECTIVES

- Identify major Protection & Control (P&C) Challenges with Distributed Generation (DG) Connections
- Discuss Mitigation of P&C Challenges
- Acknowledge advantages of Transfer-Trip (TT) Application
- Foster important role of P&C in enabling DG
AGENDA

- Background
- Impacts on P&C assets, Challenges & Solutions
  - Transmission Side
  - Distribution Side
- Operating issues and mitigations
  - DG Interconnection Protection Challenges
  - Utility Protection
- Advantages of the Transfer Trip
- Example of an Islanding event with UFLS operation
- Summary
Québec & Ontario T & D Protection & Control

Transmission System (Tx)
Above 50kV

Distribution System (Dx)
50kV & Below

1. Transmission Station (feeders, buses, transformers etc)
2. Transmission lines

1. Distribution Station Fuses, Transformers, Re-closers etc
2. Distribution lines
Total Distributed Generation connected at Distribution:
2865 MW

- Wind 473 MW
- Solar 1236 MW
- Bio/CoGen 185 MW
- Gas 362 MW
- Hydro 383 MW
- Other (Steam) 226 MW
- Micro 115 MW (Each project < 10 KW)

Total DG Connected - mid 2015
Total DG Connected - mid 2015

Total Distributed Generation connected at Transmission:
3395 MW

- Wind 3255 MW
- Solar 140 MW
Impacts on P&C assets
Transmission Side

- Impacts on the Transformer Station (TS)
  - Feeder protection
  - Bus protection, Line back-up
  - Transformer protection, Automatic Voltage Reg
  - Ground Potential Rise, Neutralizing Transformer, Neutral Grounding Reactor
  - Existing Special Protection Schemes (Load Rejection and Generation Rejection schemes)
  - Network Management System
  - Under Frequency Load Shedding

- Impacts on the Transmission Line
Feeder Protection

- Feeder Protection De-Sensitization - Upgrades
- Feeder Sympathetic trips - Directioning
- Out of Phase Re-closing of the Feeder – Transfer-Trip (TT), and DG End Open Signal (DGEO)
- Protection Mis-operation due to DG Transformer Magnetizing Currents - Low Set Blocking Signal
- Protection coordination with downstream devices
- Ensure capacity of feeder breaker CT is not exceeded
Bus Protection

- Low impedance Bus differential protection is not affected but may no longer prove to be secure

- Bus blocking scheme must be reviewed and may need directioning
  - Bus blocking scheme is not affected by DG for faults occurring on the feeder
  - Bus blocking scheme *is affected* by DG for faults occurring on the bus

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Fault current flows thru feeder protection and bus protection CTs.

Bus A Protection
\[ I_{\text{Abus relay}} = \sum I_{T1} + I_{T2} = I_F \]
- 32 ms coordination delay
- F1 block signal prevents trip
  Bus A remains in service.

Feeder protection operates, sends a bus blocking signal to Bus A.

Feeder Fault on Feeder F1

Bus B Protection
\[ I_{\text{Bbus relay}} = \sum I_{T2} - I_{T2} = 0 \]
- Bus B also remains in service.

Forced Outage

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Bus Blocking Scheme – Bus Fault

Transmission System

Line 1

Line 2

DESN Transformer Station

CB’s open to trip Bus A

I_{Abus} = \sum I_{T1} + I_{T2} - 32 ms coordination delay
CTs add fault current for Bus A; Bus A protection operates

Feeder #1

Bus A

F1-21

Bus Fault with no DG

Feeder #2

Bus B

F2-21

I_{Bbus} = \sum I_{T2} - I_{T2} = 0 - Bus B remains in service.
CTs circulates fault current for Bus B; Bus B remains in service.

Forced outage

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Bus Blocking – Bus Fault

PROBLEM:
With DG present, CT at bus tie measures additional DG fault current which creates an imbalance causing the protection for the healthy Bus B to false operate. Bus forced outage is more widespread than necessary.

SOLUTION:
Directioning of B bus blocking relays will prevent false operation for faults on A bus. This allows faults to be precisely isolated.

CTs add fault current for Bus A; Bus A protection operates

No fault current at Feeder of bus A thus no operation and blocking signal not sent

Feeder 2 protection does not operate because directioned thus blocking signal is not sent

Forced outage

Bus Fault with DG on feeder F2

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A fault on one transmission line can be fed by the other transmission line because the transformer station creates a path for electric current between the two lines.

Line Protections detect the fault and respond by taking the line out of service.

Also, a Transfer Trip Signal is sent to the TS so that the LV CB will open. This cuts off the electrical path between the two lines.

In case the Transfer Trip fails however, line back-up protection is required. Line back-up is implemented at the station, and can also signal the LV CB to open during a line fault.

All TS’s fed by two lines are equipped with Line Back-Up Protection.
Transformer Stations (TS) that are supplied by one line and have no DG’s connected downstream, do not require Line Back-Up Protection. This is because there is no current sourcing from within the TS that can feed the fault on the transmission line. The fault is managed by the Line Protections.

**PROBLEM:** Once a DG is connected, the line fault can be fed through the TS by the DG. It is therefore necessary to send a Transfer Trip signal to open the DG CB.

However, this station does not have Line Back-Up protections to safeguard against a Transfer Trip failure. If the Transfer Trip had failed, the DG would have fed the fault.

**SOLUTION:** Line Back-Up Protections must be installed at TS if DGs are present. This ensures that line fault will not be fed by DG’s if there is a failure on the transfer trip.
Transformer Differential protection at stations having three winding transformers; needs to be upgraded to provide separate restraint windings.

Transformer LV breaker re-closing scheme may need changes (sync-check may be needed).

Restricted ground fault protection may be required if the NGR impedance is increased.
- Overload protections, monitoring of reverse flows, total current harmonics and winding temperatures may also be required

- ULTC voltage regulation may have to be reviewed/changed for reverse P / forward Q flows

- Volts/Hertz relay may need to be considered for over-fluxing
- Increased Ground Fault level
  - increases Ground Potential Rise (GPR)
  - requires Neutralizing Transformer (NT) voltage rating and spare communications ports to be reviewed – may be replaced with Optical isolator
  - requires Neutral Grounding Reactor (NGR) size to be reviewed – ohms may have to be increased to respect TSC limits (Transmission System Code)

- Location of communication equipment in relay building may have to be re-assessed
Existing SPS

- Review existing Special Protection System (SPS)
  - Load Rejection (LR) and Generation Rejection (GR) schemes
  - Modifications may be required

- New Generation Rejection Schemes may be required
Network Management System (NMS)

- Upgrades needed to match the changes due to DG
- HMI display changes are required at NMS and LCC
- Existing Hub sites capacity issue and new sites
- Unbundle IED relay failure alarms for selectivity
Review existing RTU capacities:

- Protection alarm points
- Telemetry (Amp / MW) and directioning of quantities
- Operator control tripping of DG

RTU may not be adequate; upgrades, expansion or even replacements may be required

- Upgrade PCMIS to include DG relay settings
  (Protection & Control Management Information System)
Under Frequency Load Shedding (UFLS)

- Review existing UFLS scheme

- Re-configure feeder selection in UFLS
  - Feeders with DG - to be excluded, or
  - Real time intelligence in selecting feeder under UFLS (dynamic arming), or
  - Extending UFLS to DS and re-closer level
Transmission line protection issues

Consideration of:
- Changes due to on-going protection relay replacement programs and/or Tx connected generations
- Telecom changes

Impacts on re-closing circuit
- Re-closing schemes & timing
- Keying of T/T and receiving of DGEO signal
• Non-Overlapping Zone 1 Protections
• Enlarged apparent impedance
• Current Out feed (Current Reversal)
If zone 1 elements are required not to trip fault beyond new tapped generation CB, the instantaneous zone 1 protection will not be overlapping. The gap area between the reaches of two zone 1s must be protected by teleprotection scheme.
Enlarged apparent impedance

\[ Z_{\text{App}} = \frac{V_1}{I_1} = \frac{Z_1 I_1 + Z_2 I_2}{I_1} = Z_L + Z_2 \frac{I_G}{I_1} \]
When a paralleling path exists, the tapped generation may cause current reversal. The distance element will sense a fault close to the remote station as a backward fault.
Impacts on P&C assets
Distribution Side

- Feeder re-closer controller settings, protection coordination & fuse saving?
- Need for HV side automatic interrupting device at DS?
- Incorporate blocking scheme?
- Un-cleared low level faults between existing HV fuse and station re-closer section?
- Sympathetic Tripping - false tripping of a healthy feeder on adjacent feeder faults?
- Need for communications at re-closers?
Operating issues and mitigations

ISLANDING

Planned Outage

DESN Transformer Station (TS)

Bus A

Bus B

Transmission Line 1

Transmission Line 2

ISLANDING

Bus A

Bus B

Transmission Line 1

Transmission Line 2

ISLANDING

Bus A

Bus B

Transmission Line 1

Transmission Line 2

Current Transformer

Circuit Breaker

DSN Transformer Station (TS)

Transformer Station (TS) Fence

DS Transformer

Distribution Station (DS)

Re-closer

DS Fence

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Overcurrent Protection difficult to set at DG locations.

- Inverters - Maximum current about 1.2 p.u., less if DG running at less than max capacity, so there is not enough difference between load and fault for relay to distinguish using over-current

Rely on undervoltage element to trip DG.

- Does not always work!!
- Faults far away from PCC not visible to DG.
What about Distance Protection?

- **Zone 1** = 75-80% of Z1
  - (Instantaneous fault clearance for overlap zone, and high speed trip for rest).

- **Zone 2 (P)** = 120-125% of Max Apparent Impedance.
  - (High speed or Fast trip for entire line and backed-up with Time Delay trip, usually 400ms).

- By setting Zone 2 to 120% of the Max Apparent Impedance for remote 3 phase fault, the relay reach becomes huge.

- With interface transformer HV winding ungrounded the ground distance protection not applicable
Inverters limit fault current & maintain constant power factor dynamically.

Inverters behaviour during fault is important before determining the suitability of the relaying at the DG.

Inverters modeled as a current limiting source
DG Interconnection Protection

Typical shortcomings

- DG in-feed to a fault anywhere on the Dx can be virtually identical for inverters.

- All Dx/Tx faults are in the same direction. Direction cannot be used to avoid tripping for faults on adjacent feeders.

- Current only, voltage only or distance cannot be used to avoid tripping for faults on adjacent feeders.

- However, distance offers greater precision compared to overcurrent when reach discrimination is required.
• DG never is certain of the fault location and whether it needs to trip or ride through. Without TT - DG need to delay tripping (at least 150ms) after the utility trips.

• Even with the longer delays it is difficult to avoid DG nuisance trips for adjacent feeder permanent faults that are cleared by timed protection elements.

• Delay may be too long – due to declining fault infeeds – risk asynchronous reclosing into DG + feeder island.
Utility Protection

- Utility protection has visibility of entire feeder.

- Utility feeder protections are capable of selective detection and isolation of all faults on the feeder.

- With fault location discrimination it is determined whether or not the DG needs to be tripped for a feeder fault condition.
Where current magnitude alone is not sufficient, utility feeder protection use direction to avoid tripping for DG back-feeds to source-side faults (adjacent feeder)

- Transfer Trip (TT) can extend utility protection to the DG for fast clearing.

- Sequential delay is unavoidable when DG is not capable of detecting feeder faults & there is no TT
Adaptive Relaying

- **Distribution Generation Control Protection (DGCP)**
  - Real Time Automation Controller (RTAC) can provide the mechanism to reconfigure both the sending and receiving protection signals to/from remote field devices and feeder breakers whenever changes occur in the feeder topologies.

- The Distribution Management System (DMS) sends topology changes to the DGCP and the DGCP automatically re-configures the protection signals based on the new topology.

- Automatically switching setting groups and summing CTs prior to entering or after exiting back-to-back parallel of feeders.
Adaptive Relaying …

- Blocking the tripping for 44kV reclosers for a loss-of-protection.

- Ground backup protection at the DS to open the 44kV recloser at the station for a 27.6/13.8/8.2 kV station recloser failure condition.

- The UFLS infrastructure to allow adaptive relaying by evaluating feeder loading conditions by the DMS and having DMS automatically arm selections in real-time at the TS station, 44kV reclosers and 27.6/13.8/8.2 kV DS station reclosers based on the DG generation and loading to satisfy the target load rejection requirement at the TS.

- The 27.6/13.8/8.2 kV capacitor banks and voltage regulators can be provided with new controllers and remote control but still switch automatically based on the voltage but with the added remote control switching capability.
Advantages of Transfer Trip

- Deterministic, Most Reliable & Safest
- Non-Detection-Zone
- Operates for Inadvertent Trips
- Facilitates DGEO, LSBS
- TIMELESS
- Fault Ride-Through Possible (LVRT, LFRT)
- Expedites Restoration Efforts
- Provides Rapid Fault Clearance, Fuse Saving, Power Quality
Example of an Islanding Event

Sidney TS Configuration
Pre-Fault Condition

DG: 13MW
Total Station Load: 58MW, 30MVAR
G/L: 0.23

Planned Outage on T1

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Effect of UFLS on Islanding Event

<table>
<thead>
<tr>
<th>Time (ms)</th>
<th>f (Hz)</th>
<th>U (p.u.)</th>
<th>P (MW)</th>
<th>Events</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0</td>
<td></td>
<td></td>
<td>115kV Line Q6S Fault cleared, Islanding started</td>
</tr>
<tr>
<td>2</td>
<td>130</td>
<td>59.5</td>
<td>0.85</td>
<td>OPG Generators 81U Pickup</td>
</tr>
<tr>
<td>3</td>
<td>133</td>
<td>59.3</td>
<td>0.82</td>
<td>UFLS Stage 1 Pickup</td>
</tr>
<tr>
<td>4</td>
<td>213</td>
<td>58.8</td>
<td>0.78</td>
<td>UFLS Stage 2 Pickup</td>
</tr>
<tr>
<td>5</td>
<td>255</td>
<td>58.4</td>
<td>0.74</td>
<td>Glen Miller DG Tripped (81U setting: 58.4Hz, 0s)</td>
</tr>
</tbody>
</table>
| 6         | 500    | 56.9     | 1.05   | • Feeder M4, M3, M5, M6, M7 tripped due to UFLS
          |        |          |        | • All DG tripped except Sills Island |
| 7         | 1500   | 48.8     |        | Island Collapsed |

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- **I (R – Φ), Feeder M1**
- **3 I₀ (System, transformers neutral currents)**
- **V (R – W, Φ - Φ), LV Bus**
- **P, Feeder M1**
- **Q, Feeder M1**
- **Frequency**
Identify P&C upgrades at Tx and Dx

Detailed P&C assessment should be carried out

Adequate feeder characteristics must be provided to customer to determine relay settings at DG end

DG inter-tie protection design and relay setting must be reviewed for acceptance

Change controls
  - Feeder Model & Configuration, Short circuit levels and DG equipment changes etc.
Challenges in DG protections relay settings
  - Depending upon DG type/locations – feeder faults may not be visible to DG protections, issues with O/C & Distance Protection

DG protections have inherent disadvantages
  - Difficult trade off between DG protection sensitivity and selective – may suffer high number of nuisance trips

Utility feeder protections have advantages
  - Sensitive, Selective and Deterministic

Advantages of Transfer Trip and Adaptive Relaying to improve DG availability when not required to trip and ensure effective tripping of DGs when required to trip.
Thank You

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The purpose of this presentation is to provide information about some of the issues that Hydro One Networks Inc. (“Hydro One”) has encountered during the process of connection generation facilities to Hydro One’s distribution system. The particular concerns that must be addressed by a generation proponent in respect of the connection of its generation facility to Hydro One’s distribution system will be set out in the Connection Impact Assessment that Hydro One performs or has performed, as the case may be, for such proposed connections and this presentation is not intended to amend, modify or replace same. Hydro One will not be liable or be responsible for any consequences of the use or reliance on the information contained in this presentation.