Distribution Automation Results,
Lessons Learned, and Affect on
Smart Grid Implementation Plan at
National Grid

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ABSTRACT

National Grid has conducted a distribution automation (DA) pilot program at the 23- and 34.5-kV subtransmission levels and 13.2-kV distribution level. The subtransmission level portions were commissioned in early 2009. The distribution level portion was commissioned in mid 2010. A paper describing the pilot program and the preliminary results was presented at the 2009 DistribuTECH Conference.

This paper provides an update on the results of the DA pilot program and details the lessons learned with respect to communication, project management, corporate expectations, training, etc. It also discusses the impacts of these lessons on a larger, more advanced Smart Grid pilot program now under way at National Grid.

I. INTRODUCTION

In the late 1990s, National Grid began exploring expansion of its automation capabilities at the distribution level by applying analog and, later, digital cell phone communication to enable supervisory control and data acquisition (SCADA) of line reclosers equipped with local digital controllers. The first control system allowing computer control of line reconfiguration without operator involvement was implemented in early 2009 at the subtransmission level. It used 900-MHz spread-spectrum radios for peer-to-peer communication between the reclosers and automated switching devices, as well as backhaul to a Control Center. This control system was discussed in the 2009 DistribuTECH paper. By 2010, this technology was also applied at the distribution level.

To explore potential synergies related to metering, distributed resources, distribution automation, and communication, National Grid began development of a Smart Grid pilot program in 2008. The lessons learned from the DA pilot program will be applied to the more advanced Smart Grid pilot program.

National Grid’s vision for the Smart Grid includes a robust, two-way wireless communication system for both data and control of the distribution system, as well as automated metering. The latter provides a two-way exchange of information with customers, enabling interval measurements, determination of energy consumption, and price signaling. This information will empower customers through greater awareness and give them more choices and flexibility to manage their energy consumption. The communication system will also support a distribution automation system that uses distributed and/or centralized intelligence to remotely monitor and control substation feeder breakers, line reclosers, automated switches, switched capacitor banks, line voltage regulators, and fault indicators. Volt/VAr optimization will further enhance system efficiency. Other initiatives are also in process, including phasor measurement units on transmission and distributed resource integration on the distribution system.

National Grid expects this new automated environment to facilitate greater penetration of distributed clean energy technology such as photovoltaic and wind power, as well as plug-in hybrid electric vehicles and energy storage.
II. SCOPE OF DA PILOT PROGRAM

Two subtransmission lines and six distribution feeders were selected for the DA pilot program.

The subtransmission lines include:

Boonville-Lowville 22 Line (23 kV)
Lighthouse Hill-Mallory 22 Line (35 kV)

The distribution feeders include:

Duguid 26551, 26552, and 26553 (15 kV)
Bridgeport 16852, 16853, and 16854 (15 kV)

The distribution feeders are located in the central portion of New York State near Syracuse. The subtransmission lines are to the north of this area.

Figures 1, 2, and 3 provide one-line diagrams, with device locations, for the 15-kV distribution feeders, 35-kV subtransmission line, and 23-kV subtransmission line, respectively.
Figure 2. DA pilot program 35-kV subtransmission line.

Figure 3. DA pilot program 23-kV subtransmission line.
The table in Figure 4 summarizes the equipment used in the DA pilot program. The radio count includes the radio in each controlled device, the radio at the uplink substation, and repeater radios. A large number of repeater radios were required because the elevation changes and heavy forestation block 900-MHz signals. We had anticipated this issue and included a radio survey in addition to the typical GIS analysis, so project flow was relatively smooth.

![Table: DA Pilot Program Equipment Summary]

<table>
<thead>
<tr>
<th>Circuit</th>
<th>Voltage</th>
<th>Number of Reclosers</th>
<th>Number of ScadaMate Switches</th>
<th>Number of ScadaMate Tie Points</th>
<th>Number of Radios</th>
<th>Number of Teams</th>
</tr>
</thead>
<tbody>
<tr>
<td>Booneville-Lowville 22</td>
<td>23 kV</td>
<td>0</td>
<td>2</td>
<td>1</td>
<td>9</td>
<td>2</td>
</tr>
<tr>
<td>Mallory-Lighthouse Hill 22</td>
<td>35 kV</td>
<td>0</td>
<td>2</td>
<td>1</td>
<td>21</td>
<td>5</td>
</tr>
<tr>
<td>Chestertown-Schoon Lake 3</td>
<td>35 kV</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>8</td>
<td>0</td>
</tr>
<tr>
<td>Battenkill-Cement Mountain 5</td>
<td>35 kV</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>4</td>
<td>0</td>
</tr>
<tr>
<td>Cement Mountain-Cambridge 2</td>
<td>35 kV</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>4</td>
<td>0</td>
</tr>
<tr>
<td>Cambridge-Hoosick 3</td>
<td>35 kV</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>12</td>
<td>0</td>
</tr>
<tr>
<td>Duguid 26551</td>
<td>15 kV</td>
<td>3</td>
<td>1</td>
<td>2</td>
<td>***</td>
<td>4</td>
</tr>
<tr>
<td>Duguid 26552</td>
<td>15 kV</td>
<td>2</td>
<td>1</td>
<td>2</td>
<td>***</td>
<td>3</td>
</tr>
<tr>
<td>Duguid 26553</td>
<td>15 kV</td>
<td>0</td>
<td>1</td>
<td>1*</td>
<td>***</td>
<td>1</td>
</tr>
<tr>
<td>Duguid - Dewitt for back haul</td>
<td>--</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>***</td>
<td>0</td>
</tr>
<tr>
<td>Bridgeport 16852</td>
<td>15 kV</td>
<td>2</td>
<td>1</td>
<td>2</td>
<td>****</td>
<td>3</td>
</tr>
<tr>
<td>Bridgeport 16853</td>
<td>15 kV</td>
<td>2</td>
<td>1</td>
<td>3*</td>
<td>****</td>
<td>3</td>
</tr>
<tr>
<td>Bridgeport 16854</td>
<td>15 kV</td>
<td>1</td>
<td>1</td>
<td>2**</td>
<td>****</td>
<td>2</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td>11</td>
<td>16</td>
<td>9</td>
<td>153</td>
<td>23</td>
</tr>
</tbody>
</table>

* counted in another feeder
** one counted on another feeder
*** 48 radios for Duguid
**** 47 radios for Bridgeport

Figure 4. DA pilot program equipment summary.
III. DA PILOT PROGRAM RESULTS

We now have two years of experience with the DA pilot program subtransmission circuits. The results are very dramatic and favorable. Figure 5 indicates the permanent and momentary interruptions on these circuits in 2005 through 2010. As a point of information, a great deal of remediation work was performed on these circuits prior to implementing the DA pilot program, which helped reduce the number of momentary interruptions and may have helped reduce the number of permanent interruptions as well.

![Number of Subtransmission Pilot Interruptions](image)

Figure 5. DA pilot program subtransmission circuit interruptions.
The impact of subtransmission circuit interruptions, in terms of Customer Minutes Interrupted per Event, is indicated in Figure 6. This figure shows the large customer impact for years prior to implementation of the DA pilot program in 2009. The program reduced customer impact so significantly in 2009 that it is barely visible in the figure, and is too small to see in 2010. This dramatic improvement is shown normalized by interruption event to allow comparison with previous years with variable interruption counts.

![Subtransmission Pilot Customer Minutes Interrupted per Permanent Event](image)

*Figure 6. Subtransmission circuit Customer Minutes Interrupted per Permanent Event.*
Figure 7 indicates the number of interruptions on the distribution mainline—the three-phase trunk of pilot feeders. Over the past several years, a number of mitigation efforts have been performed on these feeders to improve performance.

The distribution level portion of the DA pilot program experienced delays due to competing priorities for manpower and other events out of the control of the program team. As a result, equipment was installed and allowed to operate using local controls. The equipment was DA-enabled sometime later.
Figure 8 indicates Customer Minutes Interrupted per Event by Year due to interruptions on the distribution mainline. Performance has improved through growth in the number of devices with local control.
Figure 9 indicates Customer Minutes Interrupted by Event due to interruptions on the distribution mainline. It shows that customer impact prior to the DA pilot program period was improved, but performance continued to be volatile. The last event shown in Figure 9 is with automation fully activated. It portends good results, as have already been experienced at the subtransmission level.

Since we only have two months of experience with full automation at the distribution level, more time is required to better quantify the results. It appears that performance improved as more DA-enabled devices were deployed (the last six events shown in Figure 9), as one would expect. But it also looks like a great deal more improvement can be obtained when these devices are collectively automated (last event in shown in Figure 9).

![Customer Minutes Interrupted](image)

**Figure 9. Customer Minutes Interrupted by Event.**

### IV. LESSONS LEARNED

The lessons learned from the DA pilot program have been integrated into National Grid’s fault detection, isolation, and restoration (FDIR) component of our Smart Grid pilot program. These lessons have resulted to product improvements which have benefited not only National Grid, but the entire industry.

**Training**

All line crews in the pilot area and surrounding region, as well as engineers and technicians, were trained in a classroom environment to familiarize them with the new equipment and systems. In addition, the initial radio survey for the DA pilot was conducted in conjunction with S&C, which provided an opportunity for National Grid personnel, including line crews, to discuss the supplier’s product under the less-intimidating and time-constrained environment of a classroom. This arrangement helped with acceptance by Operations.
Communications

Peer-to-peer and backhaul latency and other quality issues were tested during field commissioning and found to be within spec. In later rechecking to identify an intermittent communication issue, a routing circle issue was identified just outside the furthest device. Two repeaters needed virtual coordinates to bring them into the circle. The routing circle issue is inherent to the radio technology used in the DA pilot program. It will not impact the Smart Grid pilot program, as newer technology, not so constrained, has been selected.

Radio communication links were skimpy and long. In the worst case, 20 repeater radio hops produced significant delays. Learning from this experience, future DA implementations will use a more robust communication system by either increasing the number of uplink points, thus reducing radio hops, or using newer communication technology.

At the energy management system (EMS) uplink points, DA radio communication was interfaced with the substation EMS data concentrator. The data concentrator settings selected were similar to those typically used for communication verification. These settings, optimized for substations, proved to be needless and slowed the communication links for the distribution lines, increasing the number of drops. Don’t assume that “It’s just like EMS.” Settings should be used that are optimal for the radio technology in use on the feeder, not the nearby substation environment.

Antennas generally should be mounted as high as possible on the pole. But because of conflicting working practices between crews responsible for primary circuits and those responsible for communications, which are typically located in the secondary circuit space, it was decided to mount the antennas at a neutral height. While this enhanced flexibility because either crew can work on the communication equipment, it did increase the number of repeater radios required, and thus capital cost. This issue will continue to be examined in the Smart Grid pilot program.

The Smart Grid pilot program has selected WiMax as the communication platform. This robust platform will resolve the communication issues experienced in the DA pilot program and support many other components of the Smart Grid.

Commissioning

During field commissioning, one distribution automation team unexpectedly stopped running. Subsequent investigation, analysis, and testing showed that this occurred because steps in the commissioning procedure had been performed out of sequence. The team was subsequently re-activated in a manner that did not allow it to discover the changed system state.

To ensure that all personnel involved understand the procedures to be followed, subsequent commissioning of all DA feeders will include detailed, written procedures, supplementing the check lists and training provided to crews and field engineers.

Miscellaneous

The DA switch controls do an excellent job of battery monitoring once energized in the field. But issues can occur if a control is stored for long periods and the battery is
not properly recharged every 6 months. A battery in a demo control was damaged when it was left connected while the control was transferred to another Operation Center for training. The battery was drained over the course of a week, and would not recharge when reconnected to 120 VAC.

**Procedures**

With so many devices included in the DA pilot program, commissioning had to be performed in stages. Groups of controls were enabled, commissioned for fitness for duty, and then disabled until all the feeders were ready to be activated. An “incident” occurred when, after commissioning, some teams were left in “Automatic” (fully DA-enabled) rather than temporarily disabled. During a storm, those DA devices did exactly what they were configured to do: restore power to line sections. But Dispatch was not expecting those line sections to be re-energized. Fortunately, by following standard procedures to verify de-energized and grounded status, crews averted any repercussions as a result of the incident. Procedures were improved and better documented to ensure there are no repeat occurrences.

A second “incident” involved a misoperation on a distribution feeder, resulting from miscoordination between the timers in a recloser control and the associated DA control. A lesson learned is to have a second person review and check all settings. During this investigation, it was also seen that better utilization of data available from the recloser would bolster the DA logic making the system more robust. With the cooperation of our supplier partner, the system logic was adjusted in the firmware to implement this improvement. This change will benefit not only National Grid, but the entire industry.

**V. NEXT STEPS**

The DA pilot program has been judged to be successful based on the reliability performance improvement measured and with costs at or below expectation. We will continue to monitor the performance of the DA pilot systems (particularly for distribution) to better quantify the benefit versus cost ratios over a longer operating period.

Lessons gleaned from the DA pilot will be incorporated into our Smart Grid pilot program. The supplier technology for that program has been selected and is progressing toward field implementation.

**VI. CONCLUSIONS**

National Grid embarked on a DA pilot program to establish a value relationship between DA and the other options at our disposal for maintaining and improving reliability for customers. That pilot has been deemed a success. Through a thorough understanding of the cost and benefit of DA, we are now in the position to choose the most successful reliability options, having the lowest cost impact for our customers. In this paper, we have discussed the DA pilot program that was developed and implemented to gain this knowledge, and to reduce SAIDI while we learn. We discussed specifics of the pilot project and lessons learned from it.
The journey from concept, to proof of concept, to pilot will follow a different path for each utility. It is crucial that each utility learn their own lessons in a manner that is consistent with their customer base, their regulatory environment, and geographical challenges in order to reach the plateau where investment in volume deployment can be justified. This journey can be guided (but not supplanted) by observing what other utilities have attempted.

This essentially is the journey that National Grid has embarked on in undertaking our Smart Grid project, which will establish the value relationship for the integration of DA and the many other enhanced technologies.

VII. REFERENCES


VIII. VITAE

**Vincent J. Forte, Jr.** is a Principal Engineer in National Grid’s Smart Program. Mr. Forte is a licensed professional engineer in New York State. He earned an A.S. in Engineering Science from Hudson Valley Community College in 1977 as well as a B.S. and a Master of Engineering in Electric Power Engineering from Rensselaer Polytechnic Institute, in 1978 and 1979, respectively. In the electric utility industry, he has held a number of engineering positions, including leading groups in subtransmission planning and distribution planning, as well as holding management positions, including Manager of Engineering and Director of Electric Assets. Mr. Forte has also co-authored papers and articles on customer valuation of interruptions, RF signal transmission over power distribution systems, and methods of targeting mitigation for efficient reliability improvement. He is a member of IEEE, NSPE, and HKN. Email: Vincent.Forte@us.ngrid.com

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