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Chattanooga Electric Power Board Case Study—Distribution Automation

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Executive Summary

In 2009, the U.S. Department of Energy under the American Recovery and Reinvestment Act (ARRA) awarded a grant to the Chattanooga, Tennessee, Electric Power Board (EPB) as part of the Smart Grid Investment Grant Program. The grant had the objective "to accelerate the transformation of the nation's electric grid by deploying smart grid technologies." This funding award enabled EPB to expedite the original smart grid implementation schedule from an estimated 10-12 years to 2.5 years.

With this funding, EPB invested heavily in distribution automation technologies including installing over 1,200 automated circuit switches and sensors on 171 circuits. For utilities considering a commitment to distribution automation, there are underlying questions such as the following: "What is the value?" and "What are the costs?" This case study attempts to answer these questions.

The primary benefit of distribution automation is increased reliability or reduced power outage duration and frequency. Power outages directly impact customer economics by interfering with business functions. In the past, this economic driver has been difficult to effectively evaluate. However, as this case study demonstrates, tools and analysis techniques are now available.

In this case study, the impact on customer costs associated with power outages before and after the implementation of distribution automation are compared. Two example evaluations are performed to demonstrate the benefits: 1) a savings baseline for customers under normal operations[1] and 2) customer savings for a single severe weather event. Cost calculations for customer power outages are

[1] For typical analysis of interruptions, major events such as severe storms are removed from the data so that the metrics capture the baseline reliability of the distribution system. The IEEE 1366 reliability standard defines a major event as an event that "exceeds reasonable design and/or operational limits of the electric power system."

performed using the US Department of Energy (DOE) Interruption Cost Estimate (ICE) calculator[2]. This tool uses standard metrics associated with outages and the customers to calculate cost impact.

The analysis shows that EPB customers have seen significant reliability improvements from the implementation of distribution automation. Under normal operations, the investment in distribution automation has enabled a 43.5% reduction in annual outage minutes since 2012. This has led to an estimated total savings of $26.8 million per year. Examining a single severe weather event[3], the distribution automation was able to restore power to 40,579 (nearly 56%) customers within 1–2 seconds and reduce outage minutes by 29.0%. This saved customers an estimated $23.2 million over the course of the storm.

About the Chattanooga Electric Power Board

In 1935, the City of Chattanooga established the EPB as a nonprofit agency to provide electric power to the greater Chattanooga area. Today, EPB remains one of the largest publicly owned electric power distributors in the country, serving about 174,000 homes and businesses in a 600-square-mile area. This includes greater Chattanooga and Hamilton County, portions of surrounding Tennessee counties, and parts of northern Georgia.

As a municipally owned distributor of electricity, EPB's mission is to improve the quality of life for the local community. As a result, EPB targeted economic development as a key approach to giving the local community a boost. Listening to commercial/industrial customers, EPB recognized that reliable electric power was an essential component for customer success and expansion.

In 2008, EPB began investigating the impact of electric power outages on customers as part of the planning process. Performing the economic cost analysis associated with power outages was difficult due to the lack of case studies and analysis tools. For a first order approximation EPB utilized the reported results from a Lawrence Berkeley National Laboratory study that attempted to quantify the cost of outages for US electric customers. The study estimated the annual cost of electric outages to be about $80 billion based on the entire U.S. population (LaCommare 2004). EPB assumed this cost to be linearly related to population size and scaled the value based on the population of its service area to reach an annual outage cost of $100 million.

After studying different approaches to improve distribution reliability, including distribution automation, converting overhead facilities to underground facilities, increased vegetation management, and animal protection (isolating equipment from animals), EPB determined that the emerging technology of distribution automation was the most cost-effective method to increase reliability and customer economic benefit. EPB's initial analysis showed that the installation of automated switches in both its 12

[2] http://www.icecalculator.com/, "The ICE calculator estimates the cost of power outages for residential, commercial and industrial customers based upon a nation-wide survey of electric power customers".

[3] 72,622 would have been affected were the automation not in place. Instead, there were 32,043 customers that experienced a sustained electric interruption.

kV and 46 kV circuits could potentially reduce the annual outage time by 40%. This would mean a societal benefit of $40 million dollars per year based on the annual outage cost estimate of $100 million.

In 2009, EPB received a grant as part of the DOE American Recovery and Reinvestment Act (ARRA). ARRA was intended to “significantly improve the US electric system by implementing smart grid technologies.” EPB implemented advanced distribution automation technologies, smart meters, and sensors interconnected on a fiber optic communications backbone. This new electricity distribution system includes various capabilities designed to improve resiliency, reduce the impact of power outages, improve outage response time, and allow customers greater control of their electric power use. In addition to these immediate benefits, this initial investment in smart grid automation and communication technologies is expected to facilitate future efforts to develop innovative implementations and uses of distributed generation and storage technologies.

Distribution Automation

Distribution automation provides two mechanisms for reducing both the frequency and duration of customer outages. One, the fast acting fault interrupting capability of the automation isolates the fault and protects one subset of customers from the fault. Two, for those customers that are impacted by an outage, the distribution automation can restore power rapidly to some customers depending on the location of the fault. Figure 1 shows an example of the sequence of events for a feeder with distribution automation under a fault. Initially all customers have power and are supplied from substation S101. A fault occurs (1.A) between automated switches A12 and A13, and immediately system protection is activated. The automated switch A12 opens to interrupt the fault (1.B). Finally, because this distribution system has a network topology, distribution automation can isolate the small section of line between switches A12 and A13 and connect the remaining customers to substation S301 by closing switch A15 (1.C). These automated switching actions routinely take place in 1 to 2 seconds, reducing both the customer outage time and the number of customers affected.

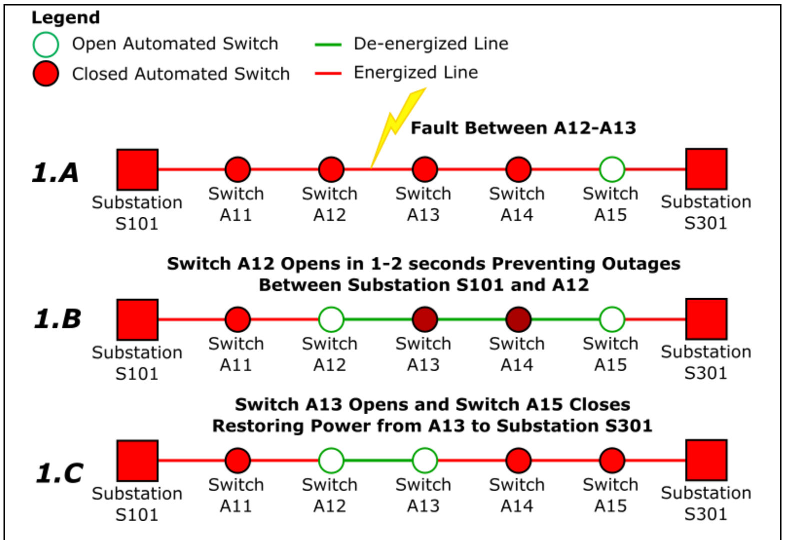

Figure 1. Outage mitigation and restoration example for a single feeder circuit.

Distribution System Implementation Cost

EPB initiated the build-out of the distribution automation equipment in late 2010, with the first switches enabled for automation in the spring of 2011. The complete system was operational by the spring of 2012. The total cost of implementing the distribution automation and integrating with other EPB systems across the service territory was about $48.4 million. This cost is composed primarily of two components: 12 kV automatic switches (IntelliRupters) and 46 kV automatic switches. EPB installed 1,200 automatic switches across the 12 kV and 46 kV distribution system circuits. These cost figures do not include the cost of the fiber optic communications infrastructure that EPB installed throughout its service territory. Fiber optic communications is utilized by EPB for all of its smart grid communications. In addition to the automated switches, EPB communicates with all of its substation equipment, AMI data collectors, line regulators and line capacitor banks with this network

Normal Operations Reliability Improvement

Utilities commonly utilize a set of indicators to describe electrical distribution reliability: 1) System Average Interruption Frequency Index (SAIFI), 2) System Average Interruption Duration Index (SAIDI), and 3) Customer Average Interruption Duration Index (CAIDI). These metrics are averaged over a distribution system's customer base during the course of a year, with interruptions due to major events such as severe storms removed from the data so that the metrics capture the baseline reliability of the distribution system. Through case studies and interview data, the associated cost for outage events has been interlinked to these metrics and the customer class and size along with other input (Sullivan 2009).

Leveraging this work and support from the U.S. Department of Energy (DOE), an online tool was created in 2012 that provides users the ability to calculate the system cost associated with SAIDI, SAIFI, and CAIDI. This tool is called the Interruption Cost Estimate (ICE) calculator[4]. This case study utilizes this tool to provide cost estimates to derive the economic improvement based on distribution automation. In this case study, the SAIDI, SAIFI, and CAIDI metrics along with annual electricity consumption are used as inputs to the tool. Other initialized input parameters by the tool are left as nominal inputs.

Normal Operation Cost Benefit from Automation

At the start of the installation of the automation equipment, EPB's annual SAIDI metric was 112 minutes, SAIFI metric was 1.42 interruptions, CAIDI metric was 79 minutes per interruption. After installation of the automation equipment, the annual SAIFI and SAIDI metrics significantly improved, with overall reduced frequency of outages and outage duration, as shown in Figures 2 and 3. As of the end of February 2015, EPB's annual SAIDI was 61.8 minutes, SAIFI was 0.69 interruptions, and CAIDI was 89.1 minutes. Significant improvements were seen in both SAIDI and SAIFI.

[4] http://www.icecalculator.com/

To calculate the customer cost savings attributable to reliability improvements from the deployment of distribution automation, the above metrics were inserted into the ICE tool[5]. The annual customer costs of power interruptions before and after automation were compared. Table 1 summarizes the results of the cost calculations. EPB's distribution automation saves their customers about $26.8 million per year.

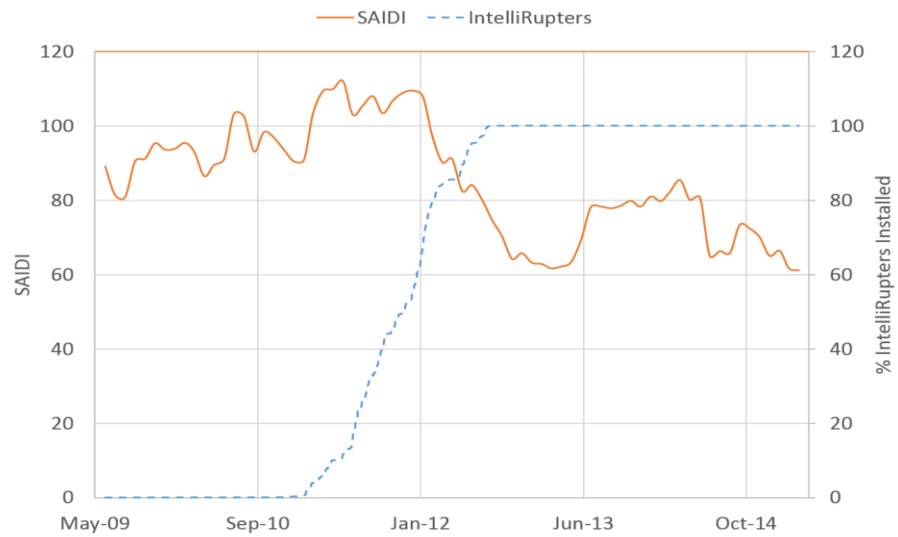

Figure 2. EPB SAIDI metric from June 2009 to April 2015.

[5] To remove changes in the customer base from the comparison, customer information from 2014 was used for both pre- and post-automation cost calculations. In 2014, EPB had 151,235 residential customers that used an average of 13.7 MWh of electricity per year, 17,699 small C&I customers that used an average of 11.4 MWh per year, and 5,309 large C&I customers that used an average of 583.3 MWh per year.

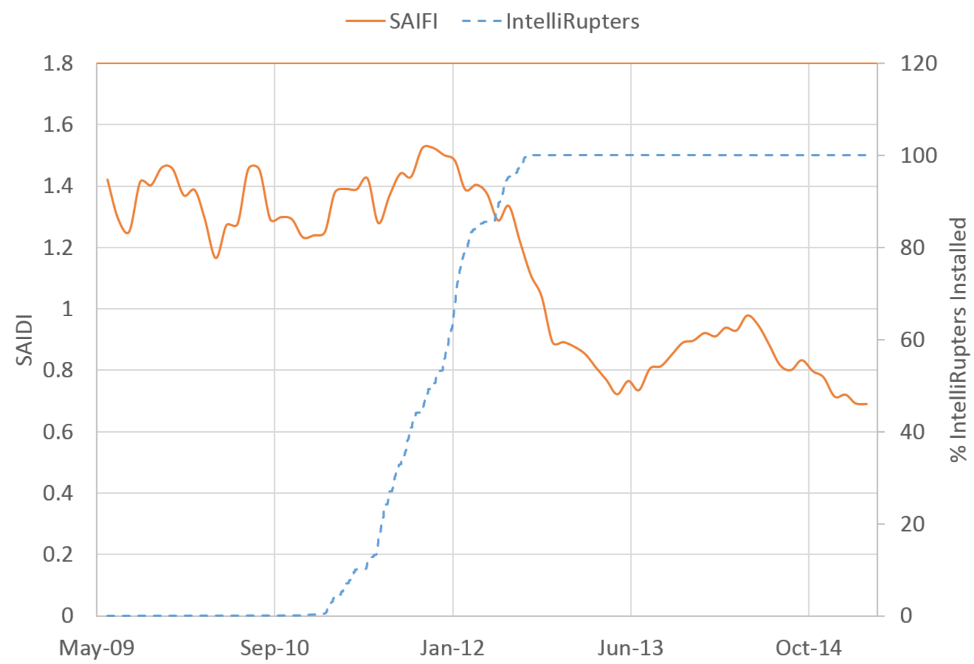

Figure 3. EPB SAIFI metric from June 2009 to April 2015.

Table 1. Nonmajor Event Cost Comparison

				Interruption Cost			
	SAIDI	SAIFI	CAIDI	Residential	Small C&I	Large C&I	Total
Pre-Automation	112	1.42	78.9	$1.207M	$16.864M	$37.699M	$55.770M
Post-Automation	61.8	0.69	89.6	$0.611M	$8.825M	$19.535M	$28.971M

Severe Weather Events

Distribution automation technologies that improve reliability are expected to have a major impact on the overall cost of severe storm events[6]. During severe weather events, outage duration and frequency increase sharply, along with the corresponding costs to customers. Power interruptions caused by severe weather events are not included in the interruption costs associated with normal operation. To quantify the economic impacts on customers of distribution system automation during major events, a detailed study of a single severe weather event was conducted and is described below. Several severe weather events have occurred since the initial installation of the EPB automation system. For this case study, the severe weather event analyzed was a summer storm that occurred on July 5, 2012.

[6] The IEEE 1366 reliability standard defines a major weather event as "an event that exceeds reasonable design and or operational limits of the electric power system."

Severe Weather Event Cost Analysis with Automation

For the severe weather event, the ICE calculator was again applied to calculate the cost of the outages. However, in this case, the cost analysis of the July 5, 2012, severe weather event was performed on a customer-by-customer basis to increase the precision of the calculation[7]. The cost analysis method is shown in Figure 4. For each customer experiencing an outage or outages, information about the customer type (residential, small C&I, or large C&I) and individual customer's annual electricity consumption was assembled using the EPB Customer Information System. Then outage times and durations were calculated for each customer using data from the EPB Outage Management System. The percentages for each hour of the day and the percentages for weekday versus weekend were calculated for each customer's outages. Using the outage data, SAIFI and SAIDI values were calculated for each customer.

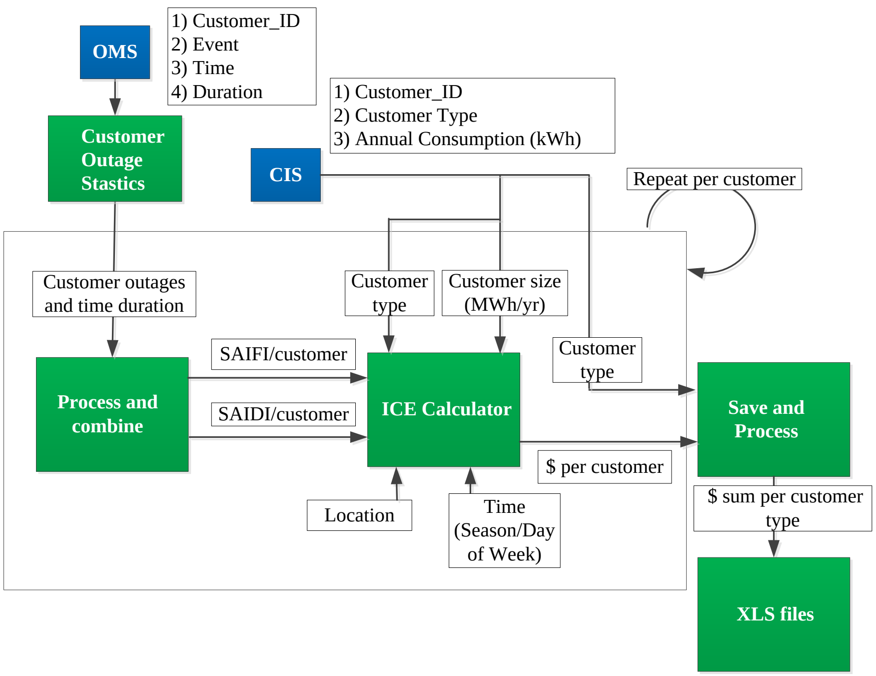

Figure 4. Method for cost estimation. (OMS = Outage Management System, CIS = Customer Information System, ICE = Interruption Cost Estimate (calculator), and XLS = eXceL Spreadsheet.)

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[7] ORNL developed a scripting tool that interfaced with the ICE calculator and EPB datasets to insert the data automatically. This allowed each individual customer to be represented. This ICE calculator cost estimate accuracy can be improved by including detailed customer information in the cost model. This detailed customer information includes not only outage duration, frequency, and customer class, but also customer annual consumption, outage time of day, outage day of week, and customer location. The accuracy of the cost estimate can be further improved by calculating the outage cost for individual customers as opposed to averaging outage statistics over all customers. The additional data available from the EPB distribution automation system makes incorporating this detailed information about individual customer outages into the cost calculation possible.

Severe Weather Cost Analysis without Automation

Before implementation of distribution automation, EPB did not have the capability to automatically isolate subsections of feeders and reroute power to other subsections. Consequently, a fault on a feeder would cause all customers on that feeder to experience an outage. The distribution automation technology allows fault locations to be more precisely located on feeder subsections. Combining this information with customer locations and the distribution system topology, the number of customers that would have lost power without automation was calculated to quantify the cost of the severe weather event without the automation technology.

Calculating the cost to customers of the severe weather event without automation also required estimating the outage times that customers would have experienced if the power were manually restored. On a feeder with no automatic switching, customers would have experienced prolonged outages, and EPB would have needed to dispatch repair crews to manually restore power. All customers that experienced outages lasting less than 5 minutes were assumed to have been automatically restored[8]. For these customers, the outage duration without automation was anticipated to be the average time that an EPB truck would take to arrive at the scene of the outage, find the cause of the outage, and perform manual switching to restore the customers' power. For the July 5 event, 56 feeders were affected and 10 switching crews were available. This yields an estimated restoration time without automation of 16.8 hours.

Cost Analysis Results

Figure 5 shows the results from the severe weather storm outage cost analysis. The cost of outages is many millions of dollars lower with distribution automation. The vast majority of the avoided outages were residential, but the greatest cost savings came from avoiding C&I outages. Table 2 also summarizes these results. With automation, EPB saw a reduction in customer outages of nearly 56% and an overall outage cost reduction of 33%. The overall cost savings from avoided outages during this storm totaled more than $23 million.

[8] Some circuits that did not automatically restore (various reasons described below), but a dispatcher was able to recognize the issue, review options for switching and use SCADA control to remotely restore service. These operations generally take 2-3 minutes to execute.

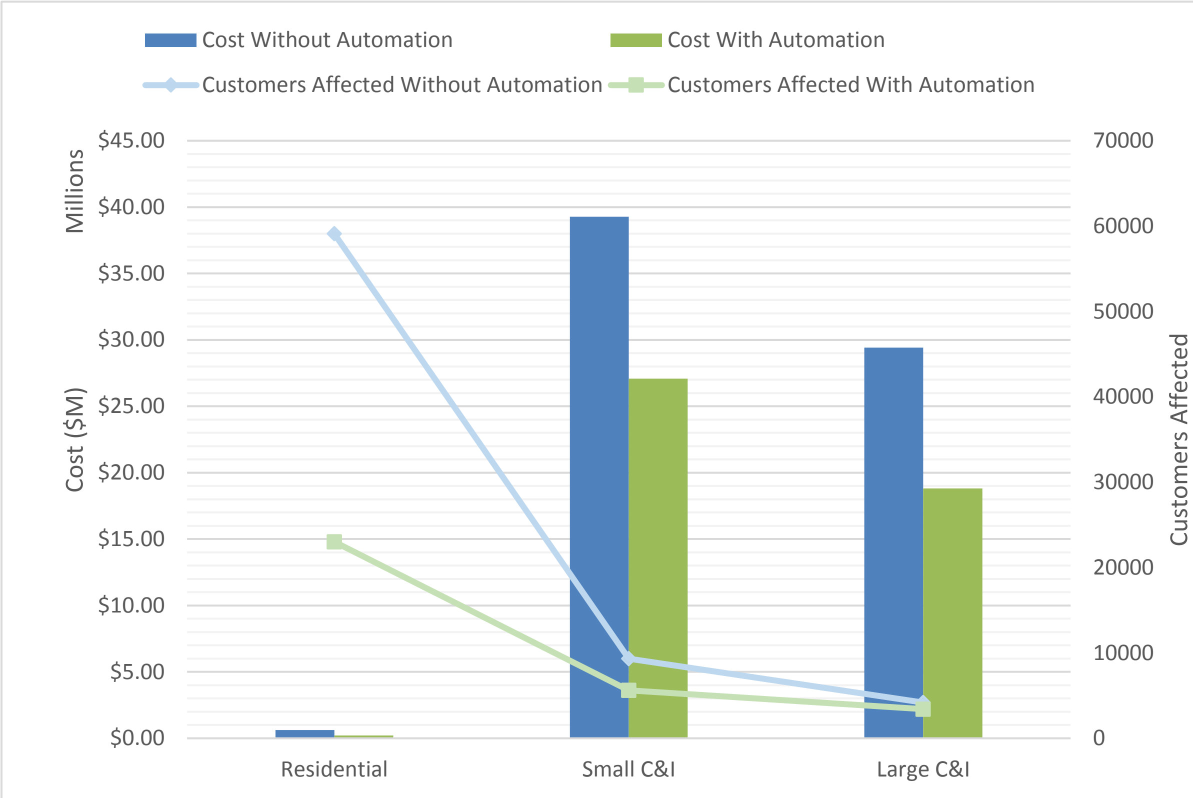

Figure 5. Results of cost analysis.

Table 2. Comparison of Costs With and Without Automation

	Without Automation	With Automation	Difference	Improvement
Customers with an Outage	72622	32043	40579	55.88%
Cost of all Outages	**$69.3M**	**$46.1M**	**$23.2M**	**33.48%**
Outage Minutes	16,986,240	12,059,524	4,926,716	29.00%
Residential Customer Total	59106	23020	36086	61.05%
Residential Customer % of Total	81.39%	71.84%	88.93%	
Residential Cost Total	**$0.6M**	**$0.2M**	**$0.4M**	**65.02%**
Residential Cost % of Total	0.90%	0.47%	1.75%	
Small C&I Customer Total	9333	5608	3725	39.91%
Small C&I Customer % of Total	12.85%	17.50%	9.18%	
Small C&I Cost Total	**$39.3M**	**$27.1M**	**$12.2M**	**31.03%**
Small C&I Cost % of Total	56.65%	58.74%	52.49%	
Large C&I Customer Total	4183	3415	768	18.36%
Large C&I Customer % of Total	5.76%	10.66%	1.89%	
Large C&I Cost Total	**$29.4M**	**$18.8M**	**$10.6M**	**36.09%**
Large C&I Cost % of Total	42.45%	40.78%	45.76%	

Figure 6 shows the EPB system before, during, and after the storm that occurred July 5, 2012. This further illustrates that the benefit of automation is amplified during major storm response. Figure 6A is a depiction of the system before the event where all EPB customers were in service. Figure 6B is the outage map about 1 hour after the storm passed through the area. The automatic switching events that restored a large portion of the system are shown in purple. The small pockets of red indicate outages that required manual repair/restoration. Figure 6C shows the system after service was restored to all customers, with areas requiring manual restoration shown in green and areas that received automatic restoration in purple.

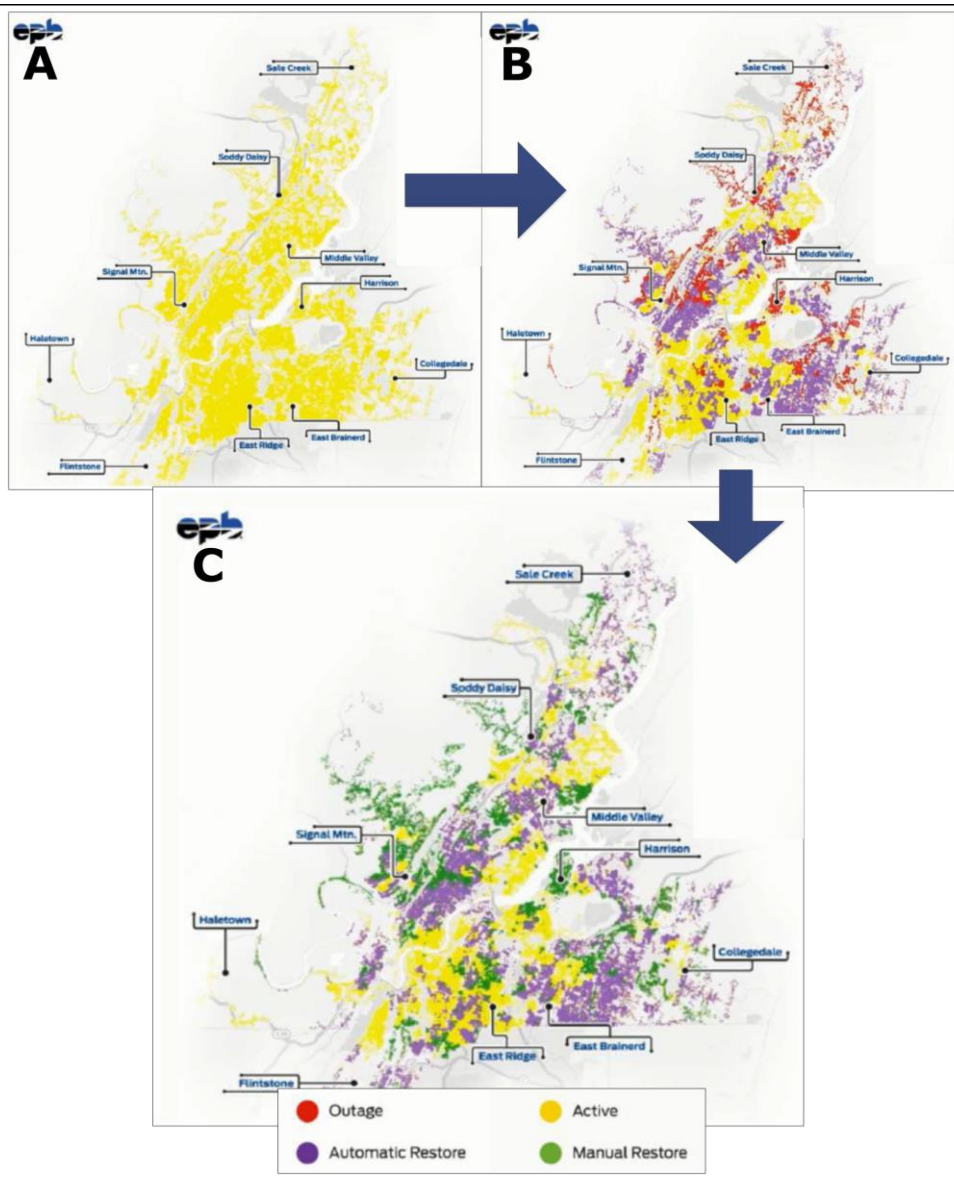

Figure 6. Outage restoration map for EPB on July 5, 2012.

Conclusion

The benefits of distribution automation can be observed in the context of both normal operations and severe weather events. For normal operations[9], the cost analysis showed that EPB's distribution automation saves their customers an estimated $26.8 million per year. For a severe weather event as presented in this case study, EPB's distribution automation project prevented $23.2 million in customer costs, more than 40,000 customer outages, and 4.9 million customer outage minutes. C&I customers accounted for 98.25% of the total avoided costs, while residential customers accounted for 88.93% of avoided outages. These results show that EPB's decision to invest $48.4 million in grid distribution automation technology was a very cost-effective investment for improving societal benefits through reduced customer minutes of interruption, increased reliability, and reduced costs of outages for C&I customers.

References

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Sullivan, Michael J., Matthew Mercurio, Josh Schellenberg, and M.A Freeman, 2009. *Estimated Value of Service Reliability for Electric Utility Customers in the United States*, LBNL-2132E, available online at http://certs.lbl.gov/pdf/lbnl-2132e.pdf.

[9] Utilizing data collected on SAIFI and SAIDI for pre-automation and current