ICE Calculator Case Study Overview: EPB Chattanooga Distribution Automation

Basic Facts[1]

Utility: EPB Chattanooga

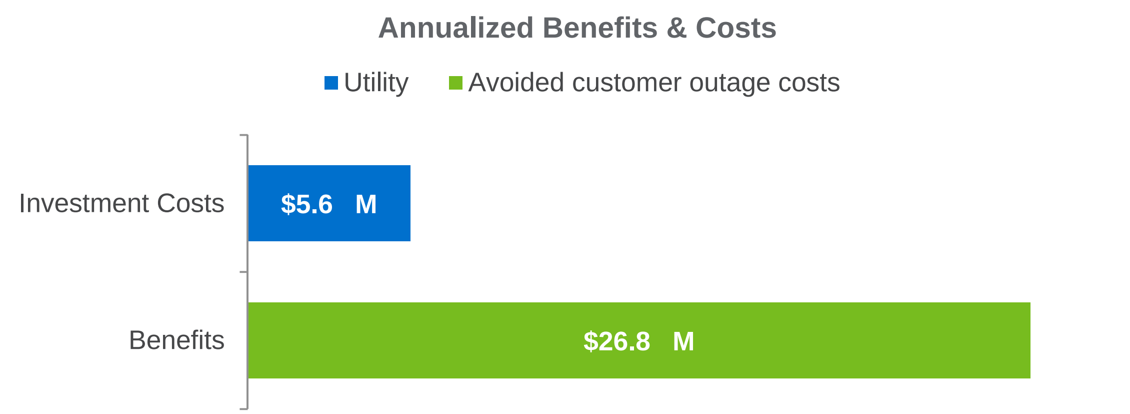
Customers Impacted: 174,000 customers (entire territory)

Proposed Investment: 1,200 automated circuit switches and sensors on 171 circuits

Reliability Improvement Achieved:

Comparison of metrics before (2010) and after (2015):
SAIDI ↓45% (from 112 to 61.8 minutes / year)
SAIFI ↓51% (from 1.42 to 0.69 interruptions / year)

Benefits & Costs



Lifetime of Benefit Calculated: $26.8M per year (2014$). Benefit shown for non-severe weather events only.

Lifetime of Cost Calculated: $5.6M per year ($48.4M annualized over an assumed useful life of 20 years).

Benefit Estimation Method: Used ICE Calculator Version 1.0 along with individual customer electricity usage and achieved improvements in reliability metrics to estimate and compare annual customer outage costs before and after automation.

[1] This case study was adapted from a report and analysis developed by Oak Ridge National Laboratory (ORNL) with EPB Chattanooga.

ICE Calculator Case Study Details: EPB Chattanooga Distribution Automation

1 Executive Summary

In 2009, the U.S. Department of Energy (DOE) under the American Recovery and Reinvestment Act (ARRA) awarded a grant to the EPB Chattanooga as part of the Smart Grid Investment Grant program. This funding award enabled EPB to expedite its original smart grid implementation schedule from an estimated 10-12 years to 2.5 years.

EPB installed 1,200 automated circuit switches and sensors on 171 circuits, improving reliability across its entire service territory of about 174,000 homes and businesses at a total cost of about $48.4 million.[2] EPB's initial analysis estimated that this improvement would result in a 40% decrease in total customer outage minutes. Comparison of actual reliability metrics under normal operations[3] from before and after the automation did indeed show a substantial improvement, including reducing SAIDI[4] by 45% (from 112 to 61.8 minutes / year) and reducing SAIFI[5] by 51% (from 1.42 to 0.69 interruptions / year). This substantial reliability improvement saves customers about $26.8 million annually in the form of avoided customer interruption costs, as estimated using Version 1.0 of the DOE Interruption Cost Estimate (ICE) Calculator, which is a publicly-available online tool for estimating customer interruption costs.[6] The ICE Calculator has since been updated (Version 2.0) with survey data from more recent studies.[7]

In addition to the avoided customer interruption costs under normal operations, distribution automation can significantly improve reliability and the speed of re-establishing service during severe storms, as demonstrated by a severe weather event in Chattanooga in July 2012. The ICE Calculator was again used to estimate and compare customer outage costs both with and without distribution automation. Customers who experienced automatic power restoration as a result of automation (e.g., outage durations below 5 minutes) would have had to wait an average of 16.8 hours without automation, resulting in an avoided customer interruption cost of $23 million during the severe July 2012 storm.

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2 The $48.4 million reflects the total cost for distribution automation inclusive of DOE grant funds including automatic switches, system circuits, installation, and software. It excludes the cost of preexisting fiber optic communications infrastructure.

3 For typical analyses 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."

4 System Average Interruption Duration Index. Equal to the sum of all customer interruption durations divided by the total number of customers served.

5 System Average Interruption Frequency Index. Equal to the total number of customer interruptions divided by the total number of customers served.

6 http://www.icecalculator.com/

7 Sullivan, M.J., J. Schellenberg and M. Blundell (2015). *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-6941E.

EPB's $48.4 million ($5.6 million annualized) distribution automation investment was quickly offset by the combined benefit of avoided customer outage costs for reliability improvements under normal conditions ($26.8 million annually) and under a severe weather event ($23 million). This investment will continue to yield outage cost savings for EPB customers throughout the expected 20-year lifetime of the investment.

2 The Planning Context

In 2009, EPB received a grant as part of the ARRA, which was intended to significantly improve the US electric system by implementing 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. EPB implemented advanced distribution automation technologies, smart meters, and sensors interconnected on existing fiber optic communications infrastructure. This new electricity distribution system included 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 was expected to facilitate future efforts to develop innovative implementations and uses of distributed generation and storage technologies.

3 Technical Considerations

In 2008, EPB began investigating the impact of electric power outages on customers as part of its planning process. EPB studied various alternatives to improving distribution reliability, including distribution automation, converting overhead facilities to underground facilities, increased vegetation management, and animal protection (isolating equipment from animals). EPB evaluated the cost of upgrading their system in terms of dollars per reduction in CMI. [8] Using this metric, EPB determined that the emerging technology of distribution automation was the most cost-effective method for increasing reliability and customer economic benefit. The higher cost-effectiveness was in part due to distribution automation being a one-time expense with minimum recurring operations costs and being a solution that mitigates all types of outages.

Next, EPB analyzed the degree of automation that would be most cost-effective. Full automation involved replacing all manual switches with automated switches (as opposed to replacing a subset of switches). After analyzing several feeders, EPB realized that some of the existing switches were not practical to replace with automated switches (based upon their location or their estimated benefits). EPB looked at how many customers they could keep online in the event of a fault. If a feeder had no automated switches, 100% of customers would experience an outage. For each added automated switch, an additional subset of customers could be isolated from a fault. For each feeder, EPB identified the point of diminishing returns for installing new switches or replacing all manual switches with automated switches, resulting in an average of seven automated switches per feeder.

[8] Customer Minutes Interrupted. The numerator of SAIDI.

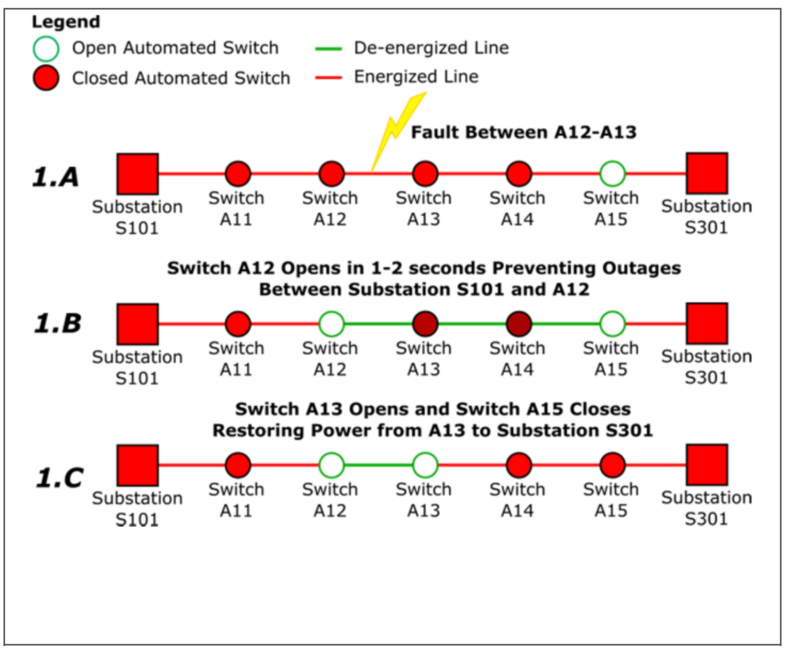
EPB's analysis showed that this level of automation in both its 12 kV and 46 kV circuits could potentially reduce annual outage time by 40% across all outage events (normal and extreme). To arrive at the 40% improvement estimate, EPB looked at CMI[9] for outages of different devices (feeders, fuses and transformers) and determined that feeder-related outage CMI would be reduced to one seventh of the original value, largely driven by the seven automated switches per feeder. The six-sevenths of CMI that was avoided made up 40% of total CMI.

Automation of distribution circuits provides two mechanisms for reducing both the frequency and duration of customer outages:

1. **Isolation of the fault**: fast acting fault interrupting capability of the automation isolates the fault and protects a subset of customers from the fault; and
2. **Rapid restoration of power**: 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



9 Customer Minutes Interrupted. The numerator of SAIDI.

4 Estimated Costs and Benefits

4.1 Estimated Costs

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. To compare equivalently with the annual outage cost savings, the $48.4 million in capital costs can be annualized, assuming a useful life of 20 years and a WACC[10] of 9.7%. This results in an annualized cost of $5.6 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 system and 200 automatic switches on its 46 kV distribution system circuits. These cost figures do not include the cost of the fiber optic communications infrastructure that EPB had already installed throughout its service territory. Fiber optic communications is utilized by EPB for all of its smart grid communications and was not included in the distribution automation cost because this network was already in place and used by EPB to communicate with all of its substation equipment, AMI data collectors, line regulators and line capacitor banks. A small portion of the total communications cost could be allocated to the automation project, but it would not be realistic to build a sufficiently robust network for that allocated amount.

The switch automation investment was deemed cost-effective because the resulting benefits significantly outweighed the $48.4 million cost. The benefits considered included the outage costs avoided by both customers and the utility. The avoided utility costs are comprised principally of the savings that are realized by avoiding truck rolls. Because automated switches can both limit the extent of an outage and restore power automatically, it becomes unnecessary in many cases for utility crews to arrive at the scene of an outage. EPB estimated a savings of about $150 per avoided truck roll.[11] Substantially more utility savings can result from avoided crew overtime pay, though this benefit may be more relevant for outages due to severe weather events during which crews are dispatched in an emergency situation, resulting in more overtime. Such savings are described in Section 4.5.

4.2 Reliability Improvements Achieved

To estimate the avoided customer outage costs due to the switch automation investments, it was necessary to evaluate the reliability improvement due to the automation as well as the quantity and types of customers who benefited. The reliability improvement was quantified by

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[10] The weighted average cost of capital (WACC) is the rate that a company is expected to pay on average to finance its assets.

[11] Based on an EPB estimate of $25 in avoided cost per switching event and 6 switching operations per fault: two to isolate the outage, one to restore power to a portion of the circuit, and the reversal of those switches to return the circuit to normal state, for a total of 6 switching events or $150 in avoided truck rolls for one outage.

changes in SAIDI, SAIFI, and CAIDI.[12] These metrics are commonly used by utilities to measure the average frequency and duration of customer interruptions across a system.

Table 1 shows the values for each reliability metric before and after EPB installed the automation switches. Significant improvements were seen in both SAIDI and SAIFI, which decreased by 45% and 51%, respectively. CAIDI increased slightly (by 12%), but this metric can increase even when SAIDI (total outage minutes) is greatly reduced because CAIDI simply measures sustained interruption duration for customers who experience outages while SAIDI spreads outage minutes across all customers. This is actually a common outcome because the outages most easily and cost-effectively addressed by distribution automation tend to be shorter in duration and less extreme. Once these initial outages are addressed those that remain may be longer, often reflected by a higher CAIDI.

Table 1: EPB Reliability Metrics Before and After Automation Investment

Metric		Value Before Automation	Value After Automation	% Change
SAIDI	Minutes per year	112	61.8	↓45%
SAIFI	Interruption per year	1.42	0.69	↓51%
CAIDI	Minutes per interruption	78.9	89.6	↑14%

4.3 Estimated Customer Benefits under Normal Operations

As described above, Version 1.0 of the ICE Calculator was used to estimate avoided customer outage costs attributable to the automation investment under normal operations. Figure 2 shows how econometric models based on customer surveys were used to create the Calculator itself (green arrows). The underlying models were derived by conducting an econometric meta-analysis of 28 customer outage cost surveys across 10 utilities from 1989 to 2005.[13] These models estimate customer outage costs as a function of outage duration, time of day, day of week, and customer segment (residential, small/medium C&I, and large C&I). Figure 2 further shows how the avoided customer outage cost (the main calculator output, orange arrow) was calculated by inputting the following into the ICE Calculator (blue arrows):

- Pre-and post-automation reliability metrics
- Customer counts; and
- Electricity usage for each customer class in EPB territory (residential, small/medium C&I, and large C&I).[14]

[12] Customer Average Interruption Duration Index. Equal to the sum of all customer interruption durations divided by the total number of customer interruptions.

[13] The ICE econometric models have since been updated with survey data from more recent studies. Report: Sullivan, M.J., J. Schellenberg and M. Blundell (2015). *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-6941E.

[14] 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 2: Customer Outage Cost Estimation Methodology under Normal Operations

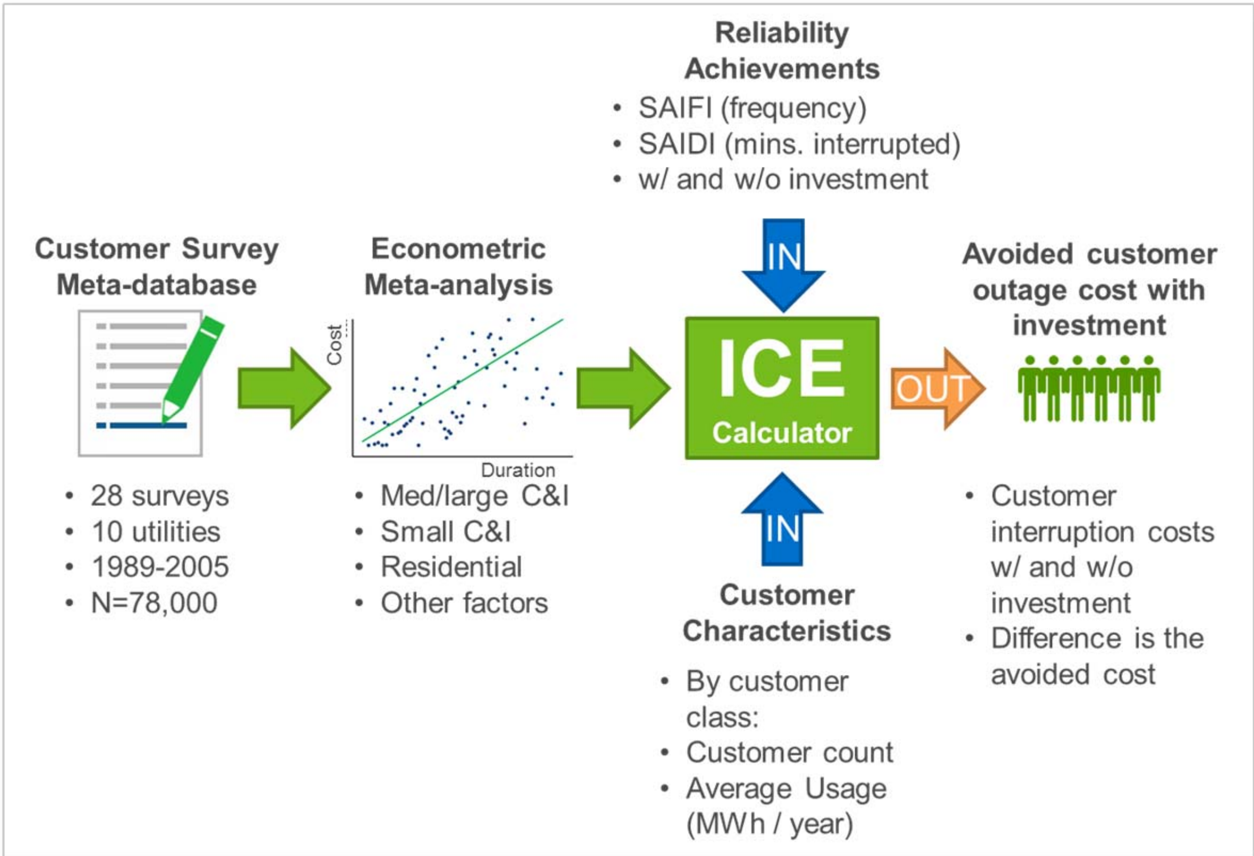
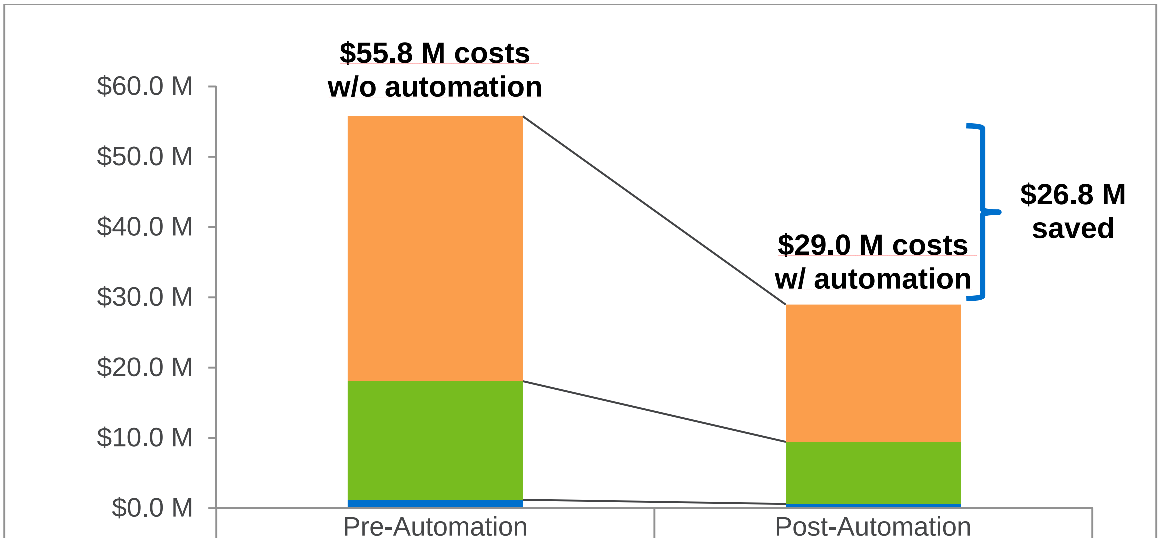


Figure 3 summarizes the annual customer outage cost estimates produced by the ICE Calculator by customer class, before and after automation. The annual customer costs were estimated to be $55.8 million before automation and $29.0 million after, meaning that EPB's distribution automation saves their customers about $26.8 million per year.

Figure 3: Comparison of Estimated Annual Customer Outage Costs Before and After Distribution Automation (Excluding Extreme Weather Events)



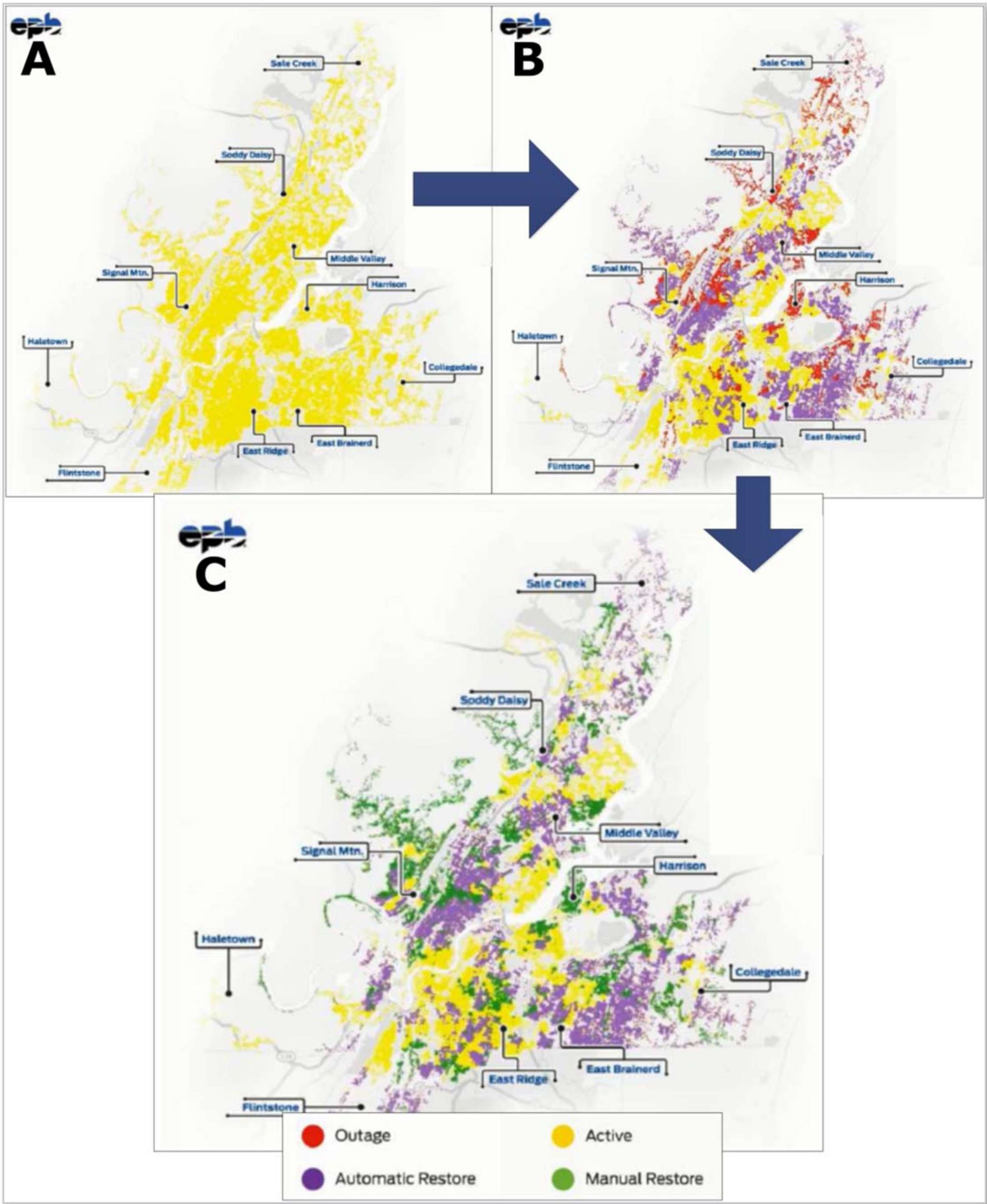
	Pre-Automation	Post-Automation
Large C&I	$37.7 M	$19.5 M
Small C&I	$16.9 M	$8.8 M
Residential	$1.2 M	$0.6 M

4.4 Estimated Customer Benefits for a Severe Weather Event

Distribution automation technologies that improve reliability are expected to have a major impact on the overall cost of severe storm events. 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 operations (estimated in Section 4.3). To quantify the customer benefits of distribution system automation during major events, a detailed study of a single severe weather event in July 2012 was conducted. Several severe weather events have occurred since the initial installation of the EPB distribution automation system. It would be possible to estimate annualized savings for severe weather events by analyzing the frequency and magnitude of events (in terms of duration, timing and number of customers affected), but that analysis was not conducted in this case.

Though severe weather analysis was not part of the initial cost-effectiveness analysis EPB performed when planning the distribution automation investment (beyond the estimated reduction in total outage minutes), the occurrence of severe weather after the distribution automation rollout provided an opportunity to demonstrate additional benefits beyond the planned improvement in outages under normal operations. This case study focuses on evaluating the customer benefits of a single severe weather event – a summer storm that occurred on July 5, 2012. Figure 4 shows the EPB system before, during, and after this storm. This illustrates that the benefit of automation is amplified during major storm response. Panel A is a depiction of the system before the event, showing that all EPB customers were in service (shown in yellow). Panel B 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. Panel C 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 4: Outage restoration map for EPB on July 5, 2012



For this severe weather event, the ICE Calculator was again applied to estimate the avoided outage cost that resulted from automatic restoration. However, unlike the calculation for avoided costs under normal operations, which used average improvements and electricity usage by customer class, the calculation for the severe weather event was performed on a customer-by-customer basis to increase the accuracy of the calculation. Oak Ridge National Laboratory (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 separately in the analysis. This ICE Calculator cost estimate accuracy was improved by including customer specific outage information in the cost model in lieu of information summed or averaged across customers. This detailed 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 additional data available from the EPB distribution automation system makes incorporating this detailed information about individual customer outages into the cost calculation possible. Incorporating this granular customer data increased the accuracy of the customer outage cost because outage cost was calculated on a customer-by-customer basis rather than on an overall basis using customer averages. For example, customers in a location where outages occur more frequently may have characteristics which do not reflect overall customer averages. If these characteristics also impact outage cost, as do consumption or customer class, it would be less accurate to estimate the outage cost for this subset of customers based on average customer characteristics.

As with the costs under normal operations, the customer outage costs avoided due to distribution automation is the difference between the estimated outage costs with and without automation. The same customer-by-customer methodology was used to estimate what the customer outage costs would have been without the distribution automation. Developing the hypothetical scenario of how customers would have been affected in absence of the automation investment 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. The roughly 41,000 customers that experienced outages lasting less than 5 minutes were assumed to have been automatically restored.[15] For these customers, the outage duration without automation was anticipated to be the average time that an EPB truck would take to arrive in the area of the outage, find the cause of the outage, and perform manual switching to restore power. For major storm events, EPB estimates 3 crew-hours per feeder to perform the switching that isolates the damage and restores unaffected sections of the feeder. For the July 2012 event, 56 feeders were affected and 10 switching crews were available, yielding an estimated restoration time per customer without automation of 16.8 hours.[16] This assumption was used in the ICE Calculator to estimate the customer outage cost without automation. With automation, average customer outage duration was about 2.4 hours shorter

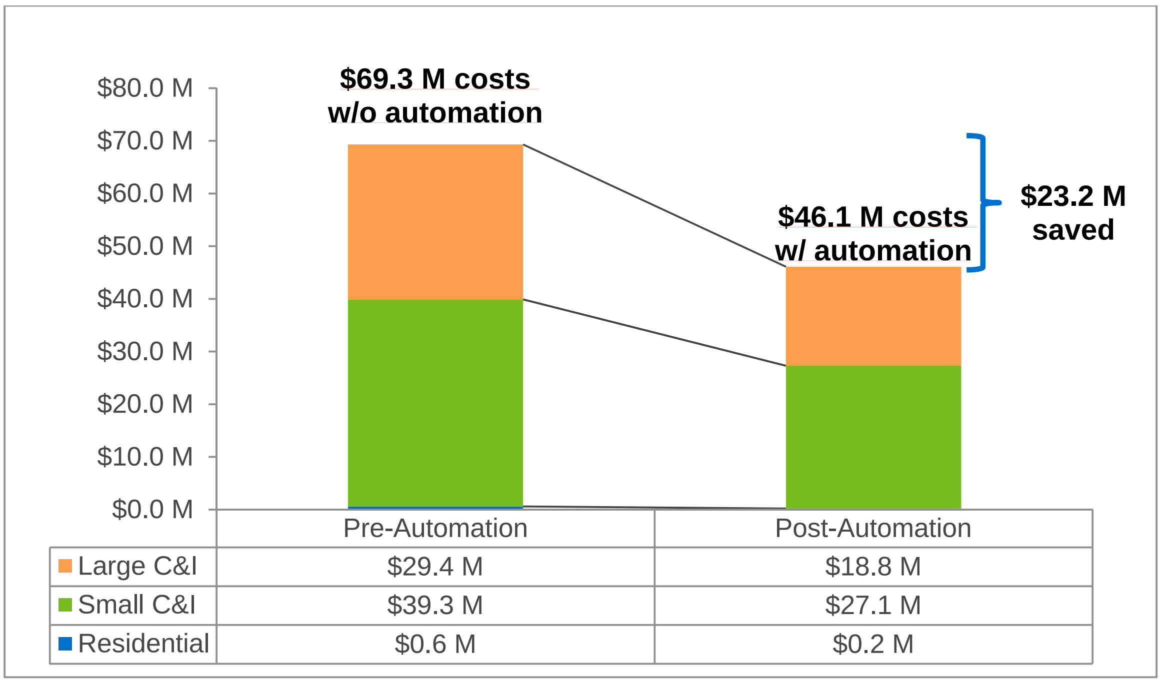
[15] Some circuits did not automatically restore for various reasons, but a dispatcher was able to recognize the issue, review options for switching and use SCADA control to remotely restore service. These operations generally take 2-3 minutes to execute.

[16] (56 feeders * 3 hours per feeder) / 10 crews = 16.8 hours

(3.9 hours instead of 6.3 hours[17]), and the outage affected 56% fewer customers than it would have without automation.

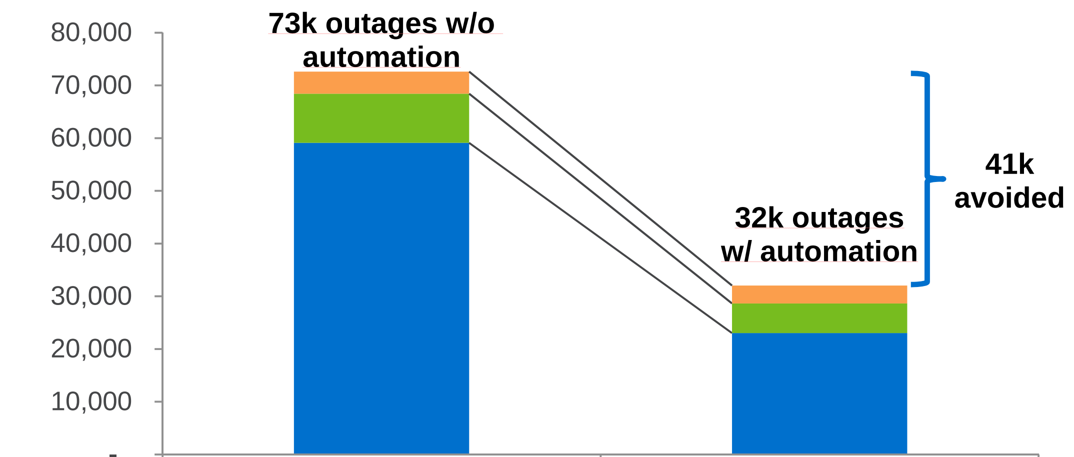
Figure 5 summarizes the outage costs avoided during the severe July 2012 storm, showing that over $23 million in customer savings were attributable to distribution automation, a 33% reduction in outage costs. Figure 6 summarizes the reduction in number of outages due to automation and underscores that avoided customer costs are not evenly distributed by customer class. The vast majority of the avoided outages were residential, but the greatest cost savings came from avoiding C&I outages.

Figure 5: Comparison of Customer Outage Costs With and Without Automation (For an Extreme Weather Event on July 5, 2012)



[17] The upper limit for outage duration in the ICE Calculator is 8 hours so this 8 hour figure was the number actually used in the computation in lieu of the EPB estimate of 16.8 hours. The reduction in outage duration cited here is based on the 8 hour figure.

Figure 6: Comparison of Number of Outages With and Without Automation (For an Extreme Weather Event on July 5, 2012)



	Pre-Automation	Post-Automation
Large C&I	4,183	3,415
Small C&I	9,333	5,608
Residential	59,106	23,020

4.5 Estimated Utility Benefits for a Severe Weather Event

As with outages under normal operations, there is also some degree of avoided outage cost savings that accrue to the utility during severe weather events in the form of reduced truck rolls and reduced overtime pay, with the latter being more substantial during severe weather events. As stated above, distribution automation saved customers 16.8 hours of outage time, but it also saved the utility 16.8 hours of overtime per crew (for all crews, not just switchmen that would have had to manually control the switches to restore power). By automatically isolating the damage, many customers were spared from the outage altogether. EPB was able to get crews working on the most significant outages (the ones with the highest number of customers). This led to the total restoration effort being completed approximately 1 day sooner, with an estimated utility restoration cost savings of approximately $1 million.

5 Discussion of Results

The benefits of distribution automation can be observed in the context of both normal operations and severe weather events. EPB's initial analysis predicted that total outage minutes could be reduced by 40% as a result of distribution automation. Actual savings as evidenced by the change in reliability metrics as well as savings during a severe weather event showed that automation resulted in substantial reductions in outage minutes and avoided customer outage costs. For normal operations, EPB's distribution automation saves customers an estimated $26.8 million per year, as a result of a 45% decrease in SAIDI and a 51% decrease in SAIFI. For a severe weather event, EPB's distribution automation prevented $23.2 million in customer costs and more than 40,000 customer outages. C&I customers accounted for 98% of the total avoided costs, while residential customers accounted for 89% of avoided outages.

6 Planning or Regulatory Outcome

These results show that EPB's decision to invest $48.4 million in distribution automation technology, with support from DOE, was a cost-effective investment for improving societal benefits through reduced customer minutes of interruption, increased reliability, and reduced costs of outages for C&I customers.