ICE Calculator Case Study Overview: CMP Distribution Automation

Basic Facts

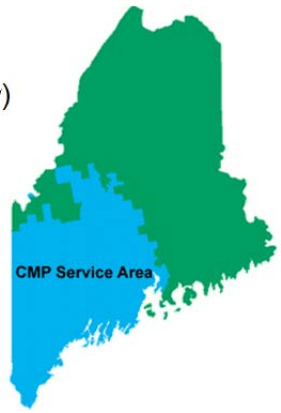
Utility: Central Maine Power (CMP), an Iberdrola company

Customers Impacted: 500,000 customers (nearly entire territory)

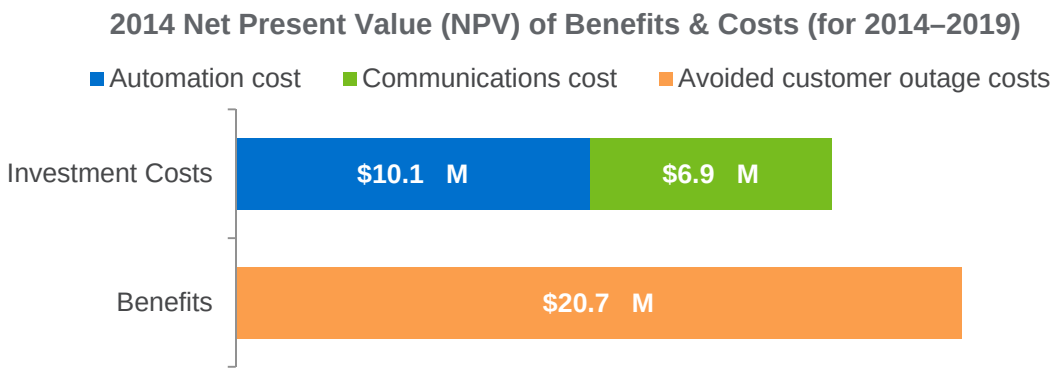
Proposed Investment: Substation and line recloser automation

Reliability Improvement Objective:

CAIDI ↓ 0.04 hours / year (from 2.00 hours/year to 1.96 hours/year), through a 15-minute reduction in duration for all outages affected by distribution automation investments



Benefits & Costs[1]



Lifetime of Benefit Calculated: 20 years, but only reported value for first 6 years (2014–2019, aligned with rate case period)

Lifetime of Cost Calculated: Levelized over 20-year asset lifetime (first 6 years reported)

Benefit Estimation Method: Used 2009 ICE econometric models to estimate customer outage costs for hundreds of historical outages that could have been mitigated by automation of substation and line reclosers. Estimated avoided customer outage costs for 15-minute reduction in outage duration per outage, calculated for the substation and line recloser investment. Benefit applied to 6-year investment rollout.

[1] Utility benefits were not considered or calculated for this case study. Costs and benefits shown are for the first 6 years of the investment (2014-2019), which aligned with the rate case period.

ICE Calculator Case Study Details: CMP Distribution Automation

1 Executive Summary

In a recent rate case, Central Maine Power (CMP) proposed distribution automation investments for substations and line reclosers throughout its service territory (around 500,000 customers). CMP projected that these investments would reduce CAIDI[2] from 2.00 hours/year to 1.96 hours/year through a 15-minute reduction in duration for all outages affected by distribution automation investments. CMP articulated the benefits of these investments to regulators in part by quantifying how incremental improvements in reliability would provide value to CMP customers by reducing customer outage costs. Avoided utility restoration costs were considered to the extent that automation may reduce headcount or overtime hours, but these utility benefits were found to be small relative to customer benefits and were not included in the rate case filing.

Avoided customer outage costs were estimated using the 2009 Interruption Cost Estimate (ICE) econometric models,[3] the development of which was funded by the Department of Energy (DOE) and Lawrence Berkeley National Laboratory (LBNL). These models were also a core input into the development of the ICE Calculator,[4] which was also funded by DOE and LBNL. This analysis estimated that for the first 6 years of the automation investments, the net present value of the customer reliability benefits was $20.7 million. This benefit was more than twice the net present value of the levelized investment cost ($10.1 million) for the first 6 years of the 20-year asset lifetime (not including the communications costs that were already incurred as part of its AMI deployment). The Maine Public Utilities Commission (PUC) ultimately approved the capital expenditures in CMP's distribution automation investment proposal.

2 The Planning Context

CMP proposed distribution automation investments as part of its 2014 rate case before the Maine PUC. After investing in smart grid pursuant to its 2008 rate case (primarily smart meters but also some substation and line automation), CMP sought to maintain its low outage frequency target (SAIFI[5] of 1.89) and to reduce customer outage minutes (reduce CAIDI from 2.0 to 1.96) by leveraging distribution automation technologies.

---

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

[3] Sullivan, M.J., M. Mercurio, and J. Schellenberg (2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-2132E.

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

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

3 Technical Considerations

CMP proposed investment in full automation of its substations and three-phase line reclosers because they produced a positive net benefit in terms of the investment cost relative to the avoided customer outage costs. Complementary investments to distribution automation were also considered in this rate case, including hardening investments to both distribution and transmission infrastructure (e.g., animal fencing, spacer cable, stronger poles, etc.). However, consideration of these hardening investments was completely separate from the consideration of automation investments and their effectiveness relative to each other was not assessed.

CMP proposed achieving the reductions in CAIDI by fully automating all of its three-phase reclosers and distribution substations (using circuit reclosers). Outages are generally identified through customer calls without automation, whereas outages are identified in near real-time with automation, complete with information about the size and location of the outage. In addition, re-establishing service in the absence of automation requires dispatch of field service crews while automation enables the circuit to be automatically reconnected once the fault has been cleared.

These proposed distribution automation investments were expected to:

- Reduce the duration of outages;
- Expedite outage notifications;
- Improve quality and speed of damage assessment; and
- Shorten the lag between damage repair and service restoration.

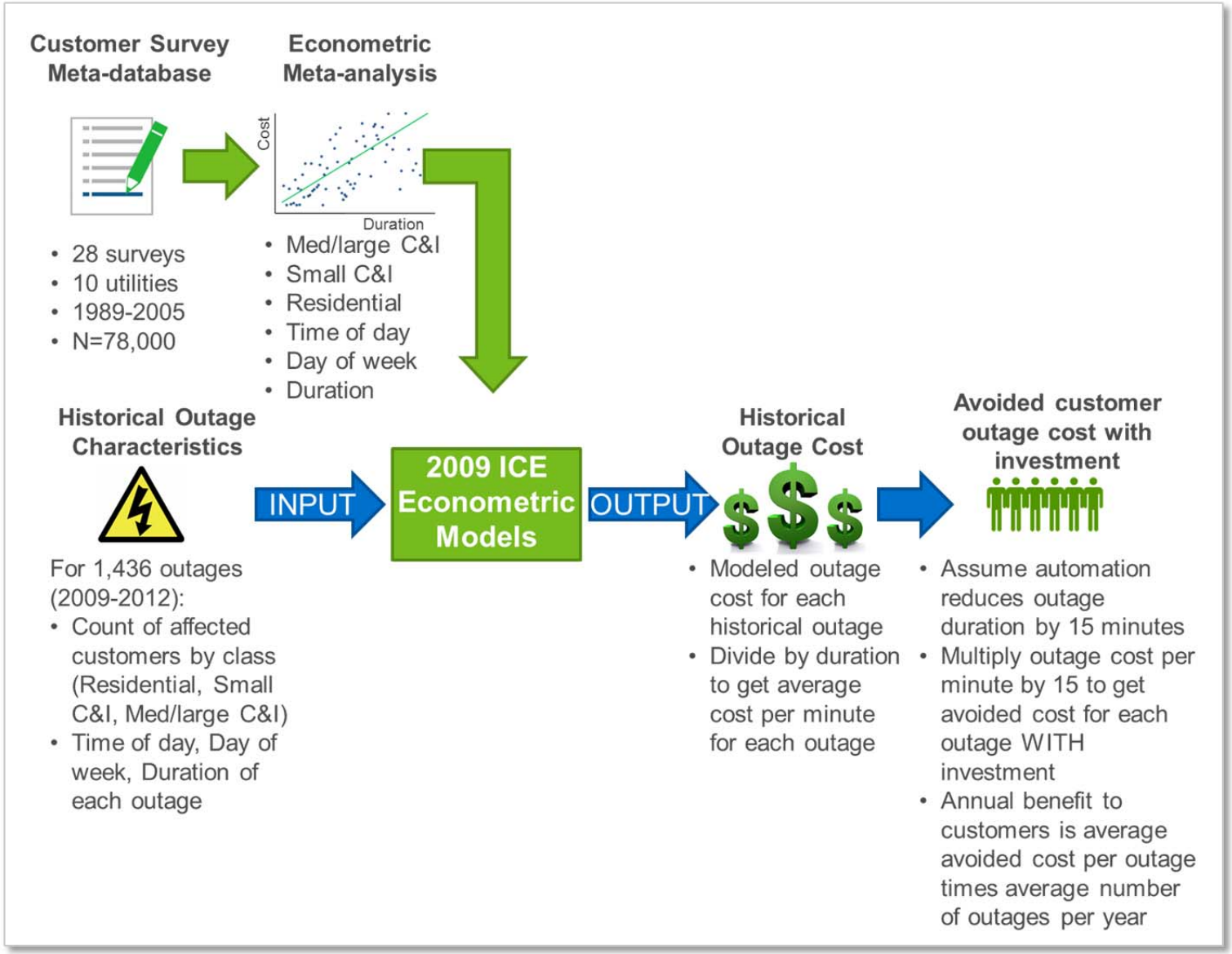
These measures were estimated to result in an average reduction of 15 minutes per outage affected by the distribution automation investments. The necessary investment to achieve full automation of substations and line reclosers was small enough (just under $25 million in capital expenditures) that CMP proposed full automation as opposed to partial automation. In situations where a far larger investment is considered, it may be necessary to optimize the use of limited funds by only targeting the automation investments to specific areas, but this analysis of partial automation was not necessary for this rate case.

4 Estimated Costs and Benefits

To estimate the benefits of the proposed distribution automation investments, outage cost values were estimated using the 2009 ICE econometric models. Figure 1 illustrates how these econometric models were developed and integrated into CMP's avoided customer outage cost estimation process. The ICE models were derived by conducting an econometric meta-analysis of dozens of customer outage cost surveys across 10 utilities from 1989 to 2005.[6] 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). CMP used these econometric models to estimate customer costs for the hundreds of historical outages that would have been impacted by the proposed automation investments.

[6] The ICE 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.

Figure 1: Avoided Customer Outage Cost Estimation Methodology Overview



The primary output from the ICE model was the estimated total customer outage costs for each outage. These costs were then converted into the customer outage cost that could be avoided with the proposed automation investment.

All avoided customer outage cost calculations were premised on the assumption that the distribution automation would lead to a 15-minute reduction in outage duration, as a result of automatic restoration of power as opposed to manual restoration requiring dispatch of field crew. CMP arrived at this assumption after conducting external and internal research. Externally, CMP spoke with other utilities that had already automated their distribution system. These utilities experienced outage duration reductions of 15 to 20 minutes on average. Internally, CMP asked service center managers in charge of dispatch about the time required to manually restore power.[7] An analyst also accompanied field crew on dispatch. Both of these inputs indicated that the average time for manual restoration was about 15 minutes.

Table 1 summarizes the benefit calculation in more detail for outages that could have been shortened by the proposed distribution automation investments on substations and circuits. It shows the primary inputs, cost per outage (A) and outage duration (B), as well as the intermediary steps and results for estimating the avoided customer outage cost benefit due to the investments. The automation benefit (C) was based on a reduction of 15 minutes in outage duration. This was estimated for every outage by taking the average cost per minute for each outage (total cost divided by duration in minutes), and then multiplying by 15 minutes. In order to reflect the fact that marginal improvements in outage duration have a differential effect for each outage, the benefit estimates in calculation steps A through C were all executed for each individual outage (not for an average across outages).

Next, the avoided customer outage cost benefit from a 15-minute reduction was summed across the total number of outages (D) and divided by the number of substations or circuits involved in the outages (E) to arrive at an average annual value per automated substation/circuit (F). The proposed automation investments included a schedule that would gradually roll out automation between 2014 and 2019, achieving full automation in 2020. The average annual value per substation/circuit (F) was applied to each investment beginning in the year it was rolled out,[8] then converted to 2014 dollars and summed to estimate a $20.7 million total avoided customer outage cost benefit for the distribution automation investments (G). Benefits were only calculated for the 2014–2019 rate case period. Finally, these total benefits were divided by the total outage hours saved over the same period (H) to produce the average benefit of $97 per customer outage hour saved (I).

[7] Including average drive time plus time to set up a truck, manually reclose, and take down the truck

[8] Annual benefits for each automation installation were apportioned with capital spend by assuming a 6-month lag to reflect implementation time for any particular year (e.g., expenditures in 2014 will only produce benefits for half that year on average). Therefore, expenditure in year X will produce 50% of annual benefits in year X and 100% of annual benefits in year X+1.

Table 1: Summary of Benefit Calculation for Distribution Automation Investments

Step in Benefit Calculation	Source of Outage	
	Substation	Circuit
A. Average total cost per outage (2008$)	$256,734	$285,425
B. Average outage duration (Hours)	2.8	6.1
C. Avoided customer costs per outage from shortening duration by 15 minutes (2008$)[9]	$29,241	$18,172
D. Average count of outages per year	101	258
E. Number of substations / circuits involved in outages	75	162
F. Average annual avoided outage cost per automated substation / circuit[10]	$39,379	$28,913
G. Full automation benefit value stream from 2014 to 2019 (2014$)[11]	$20.7 million	
H. Outage hours saved	210,000	
I. Benefit per outage hour (2014$)[12]	$97	

In CMP's rate case, this avoided customer outage cost benefit was compared to the capital costs for the distribution automation investment. These capital costs consist of ensuring remote control and monitoring capability was available at all substations and three-phase reclosers. The costs were split into two programs:

- **Substation Automation Program**: add SCADA[13] capability to the substations which were lacking remote monitoring and control capability and automate the reclosers in the remaining substations with partial SCADA capability (e.g., those that only lacked remote control of reclosers). In all, this program affects 31 substations of CMP's approximately 263 total substations; and
- **Line Automation Program**: add SCADA capability to all three-phase distribution line reclosers, starting with circuits with the worst CAIDI and SAIFI indices. In all, this program affects 134 of CMP's 472 three-phase line reclosers in service.

Incremental communications costs for the above were not included in the CMP analysis as their costs were covered in a prior AMI deployment. However, the portion of the total $27 million communications cost that could be allocated to distribution automation support[14] is roughly $10 million, or about $1.15 million per year over 20 years.[15] This would be equivalent to about $6.9 million over the 6 year period for which CMP estimated avoided outage customer costs.

---

[9] Calculated at the individual-outage level: *A / (B * 60) * 15.* The value shown in row *C* is an average across *D* outages. Marginal avoided costs of a 15 minute reduction for outages longer than 8 hours assumed to be zero due to limited data for long duration outage costs.

[10] For aggregate: $C_{summed\ across\ D\ outages} / E$

[11] Reflecting rollout schedule for automation project, adjusted to 2014$ using 9.7% GDP-PI deflator

[12] Total across both outage types: *G/H*

[13] Supervisory Control and Data Acquisition. Encrypted data communications protocol used by utilities to provide control of remote equipment.

[14] Roughly proportional to the portion of advanced meters which included a WAN radio

[15] Using the same lifetime and capital cost (9.7% GDP-PI deflator) assumptions as in the CMP calculations

In addition, some utility operations costs would be avoided because automation eliminated the need for maintenance and information retrieval trips during the year. These avoided utility operations costs were initially considered, but they were found to be small relative to customer benefits and were not included in the rate case filing.

As detailed in Table 2, aggregate capital costs for the project in 2014 dollars were estimated at $24.9 million (through 2019), inclusive of the SCADA substation installations, line recloser automation, and grid automation support allocated to the distribution automation. Levelizing this cost over an assumed 20-year asset lifetime produced a revenue requirement value stream analogous to the avoided outage cost benefit value stream (also calculated over a 20-year lifetime). CMP compared the first 6 years of the 20-year cost and benefit value streams to ensure that costs and benefits were compared for an equivalent time period (2014 to 2019). As shown in Table 2, the revenue requirement was $10.1 million for the 2014-2019 rate case period. In the rate case filing, this revenue requirement was similarly divided by the number of outage hours avoided (about 210,000), producing an estimated revenue requirement of $47 per outage hour saved.

Table 2: Summary of Annual Cost Streams for Distribution Automation Investments[16]

Year	Substation Capital Costs (2014$)	Circuit Capital Costs (2014$)	Combined Capital Costs (2014$)	Combined Revenue Requirement (2014$)	Estimated Annualized Communications Cost Allocation[17] (2014$)
2014	$2,300,000	$2,825,000	$5,125,000	$350,371	$1,150,637
2015	–	$4,075,000	$4,075,000	$966,326	$1,150,637
2016	–	$4,025,000	$4,025,000	$1,484,381	$1,150,637
2017	–	$3,975,000	$3,975,000	$1,976,797	$1,150,637
2018	–	$3,875,000	$3,875,000	$2,441,303	$1,150,637
2019	–	$3,775,000	$3,775,000	$2,875,676	$1,150,637
Total	**$2,300,000**	**$22,550,000**	**$24,850,000**	**$10,094,854**	**$6,903,819**

The reliability benefit-cost evaluation framework compared customer benefits ($97 per outage hour avoided, or $20.7 million in total) to investment costs ($47 per outage hour avoided, or $10.1 million in total), determining that the distribution automation project resulted in significantly positive net benefits during the 2014–2019 rate case period. Including the annualized communications capital cost brings to total capital cost to $17 million over 6 years.

[16] From CMP Policy Testimony, exhibit POL-6, page 3

[17] Not from CMP testimony, estimated using the assumptions described above: $10 million capital cost levelized over 20 years at a rate of 9.7%

5 Discussion of Results

The reliability evaluation framework projected that CMP's distribution automation investments would produce $20.7 million in reliability value for customers. This would be a result of around 210,000 reduced outage hours – with a reduction in CAIDI from 2.00 hours/year to 1.96 hour/year by 2018. As discussed in the previous section, the automation investment was estimated to result in a customer benefit of $20.7 million, or $97 per reduced outage hour, compared to a revenue requirement (e.g., levelized investment cost) of $10.1 million, or $47 per reduced outage hour. This resulted in a positive net benefit of $10.6 million from 2014 to 2019, or $50 per reduced outage hour. If the estimated communications cost is included, the total cost is $17.0 million and the net benefit is $3.7 million from 2014 to 2019, or about $18 per reduced outage hour.

Avoided utility outage restoration costs were not included in the analysis prepared for testimony because they were deemed insubstantial after initial consideration as there would be no measurable reduction in employee headcount, overtime or number of trucks needed as a result of the automation. That said, even though CMP expected a small incremental reduction in the overhead cost of crews or trucks, there could be operational efficiency improvements as existing resources are deployed to other tasks. If deploying a field team of two crew members costs $100/hour, the savings could be substantial. Utility outage cost savings in this respect may be as high as $1 million per day for a widespread outage.[18]

6 Planning or Regulatory Outcome

Most of the figures described in this case study were presented to the Maine PUC as part of CMP's 2014 general rate case. CMP ultimately received approval for the capital expenditures it proposed for full automation of substations and three-phase line reclosers throughout its service territory. The preceding AMI investment and the distribution automation investment were both funded in part through the DOE Smart Grid Investment Grant (SGIG) program. A DOE SGIG case study providing an overview of both the AMI and distribution automation projects can be found here:

https://www.smartgrid.gov/document/smart_meter_investments_yield_positive_results_maine

The initial CMP filing, including Testimony of the Policy Panel detailing the outage costs described in this case study can be found here:

https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2013-00168

[18] Municipal utility EPB of Chattanooga has reported savings up to $1 million per day from automation, in part due to reduced truck rolls.