

Modeling DA Improvements to Reliability Performance Metrics

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II. Abstract

Modeling DA Improvements to Reliability Performance Metrics

PHI (Pepco Holdings Inc) is one of the largest energy delivery companies in the Mid-Atlantic region, serving about 1.8 million customers in Delaware, the District of Columbia, Maryland, New Jersey and Virginia. PHI subsidiaries, Pepco, Delmarva Power and Atlantic City Electric, provide regulated electricity service; Delmarva Power also provides natural gas service. PHI provides competitive wholesale generation services through Conectiv Energy and retail energy products and services through Pepco Energy Services.¹

Distribution Automation remains very difficult to justify; furthermore, the diversity of PHI's service territory makes a single DA solution problematic. Consequently, several levels of distribution automation have been analyzed which can be applied from Urban to Rural densities. It became important to understand the costs and performance metric improvements each of these levels bring to a typical feeder.

This paper will present the models developed and the resultant calculated improvements to customer outage minutes above a base case for several levels of automation. This paper will also include costs estimates associated with each of these levels.

The analysis focused on a typical feeder configuration as shown below representing a majority of feeders in PHI's system. The model was developed to allow varying the distribution of customers across the feeder, the likeliness of a fault occurring in that section and the availability of an alternate source to back-feed the un-faulted section. The model provides for feeders with no tie switch simply by changing the availability of the alternate source to zero.

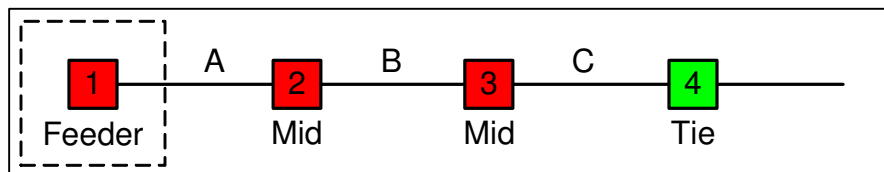


Figure 1: Feeder Used In Study

Various levels of remote control and Distribution Automation will be presented including scenarios with automatic reclosing at the Mid switches, with and without SCADA communications, with and without automatic fault detection, sectionaizaton and restoration.

III. Definitions

Sectionalizer – A device that functions as a switch to open a section of feeder in order to isolate a fault or close into an alternate feeder in order to pick up load. Sectionalizers are not designed to interrupt fault current, but rather operate during normal conditions or after a feeder has locked out. Motor Operated Disconnects (MOD's) are used as sectionalizers in the Pepco region.

Automatic Circuit Recloser (ACR) – A device that is designed to briefly interrupt a fault current for a programmed duration and then reclose the circuit for a programmed number of cycles before eventually locking out if the fault condition remains. The purpose of this device is to prevent a lockout of the entire feeder.

Lateral Reclosers – A lower current version of the ACR, the Lateral Recloser is designed to provide protection on the lateral distribution circuits.

ASR – Automatic Sectionalizing and Restoration – A logic algorithm that resides in a substation and monitors the conditions of multiple feeders. In the event of a feeder lockout, the ASR logic will automatically isolate the fault by operating sectionalizers and then close in any available ties to restore as much customer load as possible.

IV. Background

Pepco, Delmarva Power and Atlantic City Electric have been employing automation and computerization throughout their electric systems for many years and they believe that the operation and performance of their power systems is among the best in the country. Under PHI, they now believe that current advances in technology will make it possible to further enhance those systems in ways that reduce customer outages and improve operating efficiencies, while reducing the overall cost of providing services to PHI's customers. PHI has decided to develop distributed control/automation systems for its outside plant systems and substation SCADA systems.

PHI's intent is to evaluate the feasibility of embedding this new technology at a substation level for the express intent of controlling various field devices such as Motor Operated Disconnects (MODs), Sectionalizers, and Automatic Reclosers (ACRs). Presently, PHI is aggressively adding MODs and Sectionalizers to its distribution system. The control of these devices will be through PHI's EMS using either a Wireless Data Network or a leased cellular communications system. Through this experience PHI now recognizes that as more and more of these devices are added to their system and controlled by the EMS, their ability to efficiently operate these devices can be degraded due to the voluminous number of controllable points and the ability of system operators to process this information during storms.²

For this reason, PHI installed an Automatic Sectionalizing Restoration (ASR) System as an initial system to automatically localize faults, sectionalize around those faults and restore un-faulted customers. This system has been in satisfactory service for several months.

Through this experience, it became apparent that a tool that compares the costs and benefits of the various levels of automation being applied throughout the system would be an extremely valuable tool. This tool is intended to provide insight into the appropriate level of technology for various feeders with wildly varying load density, fault exposures, remoteness, and level of existing technology.

This paper and associated presentation describes the model and presents some of the results of its initial application.

V. Introduction

DA Applications

The various levels of automation that have been included in the model are shown in Figure 2. These various levels have been organized based on the level of automation and the density of customers served by the feeder. Solutions near the top of the figure represent the highest level of automation intended for the highest density of customers. The base of the pyramid represents rural customers with very little automation.

Each level, from the null case to case 7, contains a different amount of automation and communications for remote dispatch. A diverse DA committee representing the various disciplines involved to respond to faults and restore customers including dispatch and field crews. Data respect to the process followed and the various times for the actual steps was collected. Each of the automation cases were then modeled with as much real data as possible according to the simplified typical feeder shown in Figure 1 for each case in the figure below.

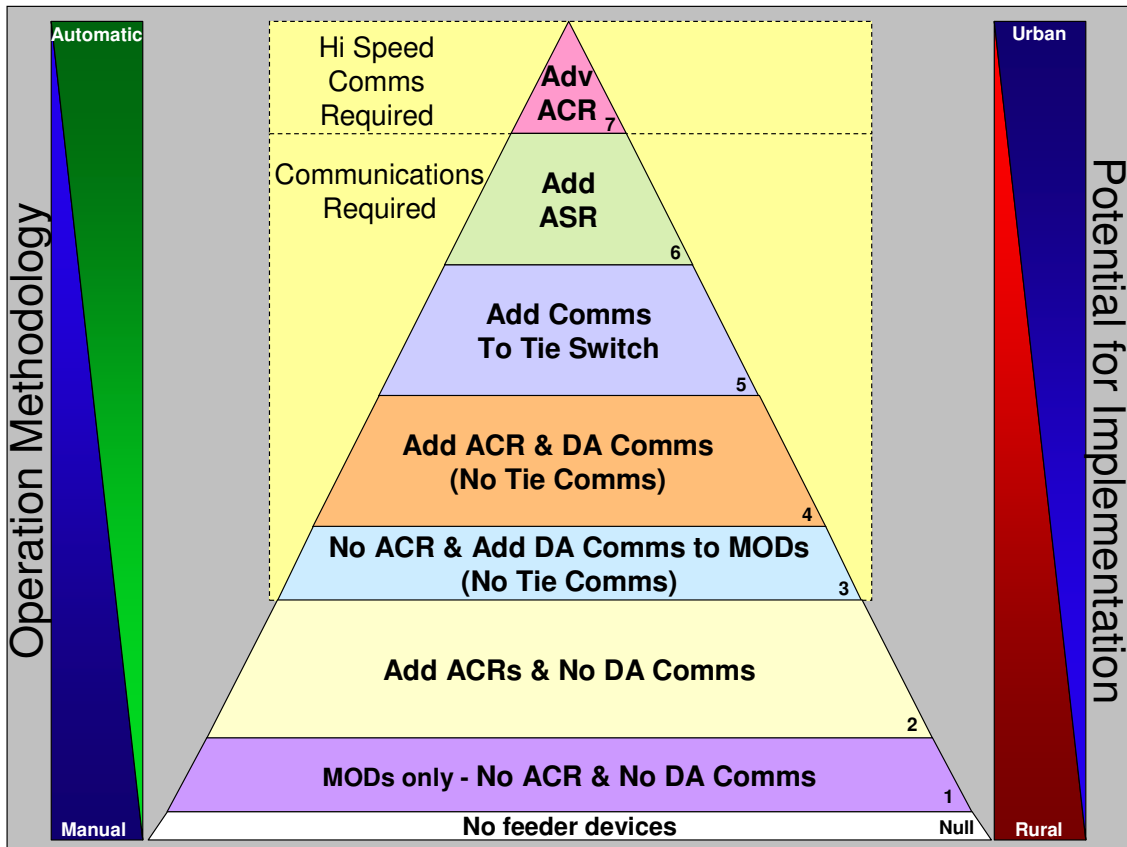


Figure 2: DA Applications Hierarchy

Null Case

The Null Case was chosen to provide a base case against which all the other cases can be compared. This system is very simple with no field switches, MODs or reclosers. The only field device is a tie switch which connects the feeder to another source. The analysis model was designed with an input which can analyze circuits with no feeder tie or when the alternate source can only be used occasionally. The feeder breaker is assumed to have SCADA communications.

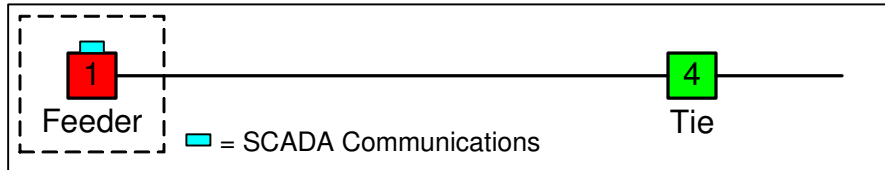


Figure 3: Null Case

Case One

This case adds two sectionalizers located along the feeder shown in Figure 4. This case also only has SCADA communications at the feeder breaker. The number of customers on each segment, including the associated radial lines, are included in the customer count in that section.

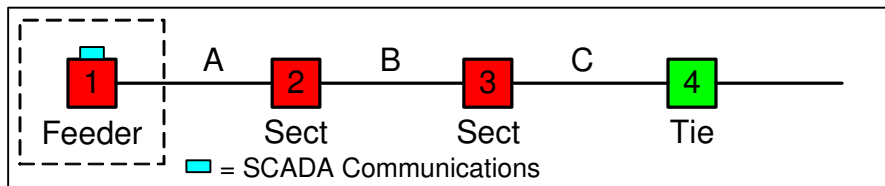


Figure 4: Case One – Add Sectionalizers

Case Two

Case Two, in Figure 5, changes the sectionalizers to Automatic Circuit Reclosers (ASR). These reclosers provide fault isolation for faults in sections B and C at switches 2 and 3, respectively.

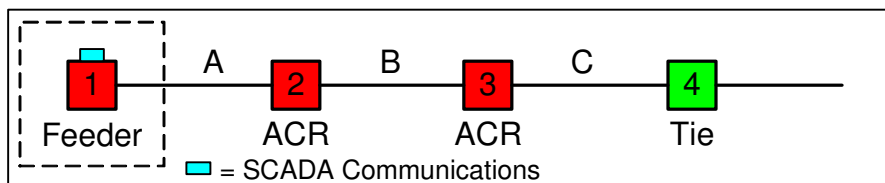


Figure 5: Case Two – Add ACRs

Case Three

This case adds SCADA communications to Case One, as shown in Figure 6.

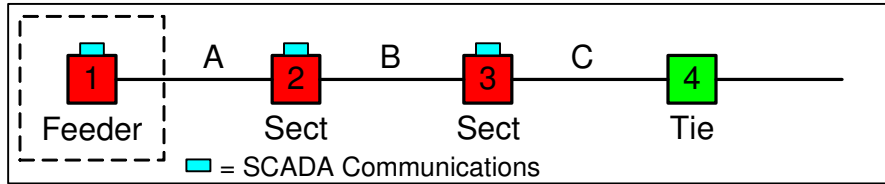


Figure 6: Case Three – Add Communications

Case Four

Case Four changes the Sectionalizers from Case 3 to ACRs. This includes the capability for fault tripping and isolation at switches 2 and 3.

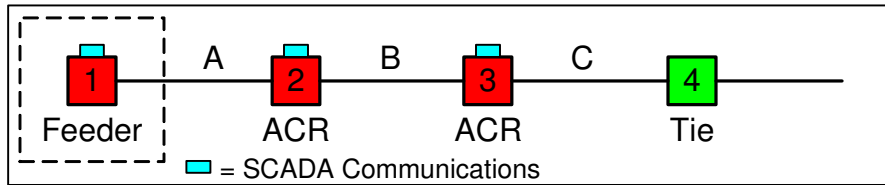


Figure 7: Case Four – Change to ACRs with Communications

Case Five

This case adds communications to the tie breaker.

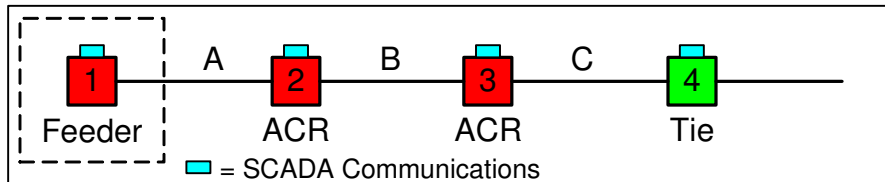


Figure 8: Case Five – Add Communications to Tie

Case Six

This case includes software in the substation that automatically localizes the fault to sections A, B, or C. Then, after the feeder goes to lockout, the software then issues control commands to open the switches around the fault and then closes the feeder breaker and/or the tie switch to restore unfaulted sections of the feeder. This option does not use fault interrupting capable switches at 2 or 3 reducing the switch cost, but also increasing the outage times for section A for faults in sections B or C.

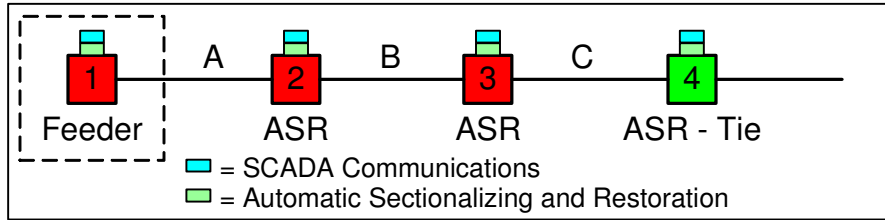


Figure 9: Case Six – Add ASR

Case Seven

Case Seven, shown in Figure 10, is an uncommon switch configuration where the tie switch is normally closed. PHI does not operate any overhead switches in this manner. This solution is a more expensive option where each switch must have high speed communications to the other switches and must include the ability to detect and trip for faults in either the forward or reverse detection.

Because the tie switch is normally closed, if a fault occurs, for example in Section C, the relays at 3 and 4 trip and send trip-block signals to the switches toward the feeder breakers at each end of the feeder. This case minimizes customer outage minutes and interruptions, however, it is the most expensive and makes distribution planning and operation much more complicated.

In recent years, this level of automation has become more possible as technology for high speed communications between switches has become more affordable. Typically, the blocking signal needs to be communicated from one switch to the others in less than 5 cycles. A limitation of this scheme is if a malfunction occurs in the communications, the outage performance would actually be significantly degraded as all the customers on both feeders would be interrupted for any fault since the blocking signal would not successfully reach the feeder breaker at either end.

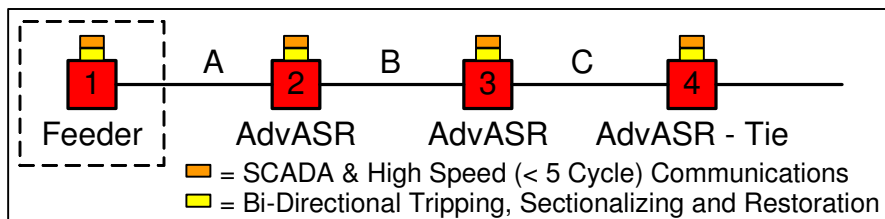


Figure 10: Case Seven – Add High Speed Comms and Advanced ASR

VI. Summary of Results

Assumptions & Feeder Variables

With each case the actual steps from outage to restoration were documented and the average time associated with each step for that case was determined. That data led to a set of common variables that will be applied to each case to provide consistency and allow the cases to be compared for the particular feeder being evaluated. The following table highlights the common user adjustable variables.

Input Value	Section A	Section B	Section C	Total	Notes
Fault Likelihood	33%	33%	33%	100%	Chances of a fault occurring in a section.
Number of Customers	600	600	600	1,800	Number of Customers along feeder
Description	Variable	Notes			
Crew Travel Time	45	Minutes for crew to reach feeder			
Simple Repair Time	30	Minutes to repair Simple Faults			
Complex Repair Time	180	Minutes to repair Complex Faults			
% Complex Faults	25%	of the faults that are Complex			
% Alt Source Used (Manual Controlled)	25%	of time alternate source used for complex faults with no Tie Comms			
% Alt Source Used (SCADA Controlled)	50%	of time alternate source used for complex faults with Tie Comms			
% Alt Source Used (ASR Controlled)	90%	of time alternate source used for complex faults with ASR			
Faults per Year	4	Total number of feeder faults including Feeder and ACR Lockouts and blown fuses per year.			
% Backbone Faults	50%	% of total faults that are on the feeder backbone - e.g. ACR or Feeder Lockout Faults per Year			
Dispatcher Busy Time	5	Average Time to Respond			

Figure 11: Model Variables

These values shown in the figure above were used to initially calculate the total customer outage minutes for each of the cases described earlier. Each variable is further described below.

Fault Likelihood – This is the likelihood of a particular fault occurring in a section of feeder with a total of 100%.

Number of Customers – This is the distribution of customers in each section of the feeder including laterals located in a particular section.

Crew Travel Time – This is the average travel and response time for the crew to arrive in the area and begin inspecting the line for trouble.

Simple Repair Time – This is the average time it takes the crew to effect repairs for simple faults, for typical tree limb related faults.

Complex Repair Time – This is the average time it takes a crew to effect repairs for complex faults which includes downed poles or conductors.

% Complex Faults – This is the percent of faults that are complex in nature, which would result in longer repair times.

% Alt Source Used (Manual Controlled) – This is the percent of times that the alternate source is used for faults in feeder sections A and B when the Tie is manually controlled. It is based on an estimate of the various times that the dispatcher elects to send the crew to manually close the tie.

% Alt Source Used (SCADA Controlled) – This is the percent of times that the alternate source is used for faults in feeder sections A and B when the Tie is controllable by the dispatcher via SCADA. It is based on an estimate of the various times that the dispatcher elects to remotely close the tie to restore load from an alternate source.

% Alt Source Used (ASR Controlled) – This is the percent of times that the alternate source is used for faults in feeder sections A and B when the Tie is automatically controlled via ASR. It is based on an estimate of the various times that the software elects to close the tie, usually representing the % chances the alternate source has capacity to pick up the sectionalized load.

Faults per Year – This variable represents the average number faults per year.

% Backbone Faults – This represents an estimate of the percentage of faults that are on the backbone of the feeder instead of possibly being isolated on a radial behind a fuse.

Dispatcher Busy – This variable represents additional time the dispatcher may take to respond to an outage during busy times.

Financial Information

The total net costs for each case was then calculated to be used in the final cost/performance comparison. While there are several financial models that could be used to capture the net total costs for each case, it was determined that a simple net present value (NPV) model would be used since it was simple and it matched the mathematical significance of the assumptions made elsewhere in the analysis.

For the Null Case to Case 5, the capital costs include only field equipment. This includes the switches and the costs of the associated communications as applicable. For Cases 2, 4 and 5, two types of fault interrupting switches were priced – a lower current version and a higher current version. These two types were switches already in use in the various regions of PHI's operating regions. Consequently, there were two price/performance ratios for those cases.

The NPV of the maintenance and communication costs were based on estimates of the annual costs taken over the life of the equipment. The NPV of these costs were a simple NPV calculation using an annual 10% rate with a 10-year life. This method of calculating total costs, while simplistic, was still within the mathematical significance of the other data and analyses.

The ASR system for Case 6 required additional investment in the station and move expensive communications. The cost per feeder was estimated by taking the total cost of installing an ASR system over a typical station with 8 feeders and allocating the station costs to each feeder. Also, the switches utilized in Case 6 are not fault interrupting switches and were less expensive and ACRs. Future analysis could include an additional case similar to Case 6 with ACRs, increasing the costs and further reducing outage duration and fault exposure. Also with Case 6, more expensive communications that provide more frequent polling and faster response for controls were used to improve performance and safety.

Case 7 is the only case not based on empirical data. This option was selected to be analyzed because it provides a further reduction to outage duration. It utilizes advanced relays with bi-directional fault interrupting switches and high speed communications. The high speed communications are required block relays outside the faulted area from interrupting customers.

Case 7 is the only case where real data is not available for the analysis for costs or the expectation of outage reduction; the data was based on engineering estimates. This case was included to highlight a very sophisticated system that minimizes the number of customers experiencing an interruption or outage.

	One time cost per feeder
Case 0	\$ 26,367
Case 1	\$ 79,101
Case 2 (Low)	\$ 92,815
Case 2 (High)	\$ 128,415
Case 3	\$ 84,048
Case 4 (Low)	\$ 97,762
Case 4 (High)	\$ 133,362
Case 5 (Low)	\$ 107,092
Case 5 (High)	\$ 160,492
Case 6	\$ 139,265
Case 7	\$ 303,072

Figure 12: Net Capital and NPV of Maintenance Costs

Analysis

Each of the cases was then analyzed to determine the typical steps and times to restore all the customers on the circuit. Care was taken to use estimated durations that represented realistic amounts. This proved to be a significant challenge because there are so many differences in variables like feeder topology, geography fault types, and dispatcher or crew response times. The team decided to take a pragmatic approach and tried to determine the “normal” time for each of the steps. The model analyzed each section of feeder, A, B, and C for two types of faults, simple and complex. The following table includes the steps taken for a fault in section A under Case 1.

Fault in Section A

Average Time

(minutes)	Description of Step
-	Fault Occurs and locks-out
0.5	Dispatcher responds to Lock-out
2.0	Dispatcher Contacts Crew
45.0	Crew Travels to Area
9.0	Dispatcher Builds Switching Orders, Crew opens #2, Dispatcher Closes #1 Tests line
20.0	Crew Locates Fault in A

Simple Fault

30.0	Crew Repairs Simple Fault
1.0	Dispatcher Creates Switching Orders
-	Dispatcher Closes 1 - Tests Line
1.0	Line Holds Lock-out Resets
10.0	Crew Travels To 2 and closes switch
-	Faulted Area Restored
-	Total Simple Fault

Complex Fault - Where alternate source is not used (or doesn't exist)

180.0	Crew Repairs Complex Fault
-------	----------------------------

	1.0	Dispatcher Creates Switching Orders
7	-	Dispatcher Closes 1 - Tests Line
	1.0	Line Holds Lock-out Resets
	10.0	Crew Travels To 2 and closes switch
	-	Faulted Area Restored Crew opens Tie
	-	Total Complex Fault
		Complex Fault - Where alternate source is used
	15.0	Crew Travels to Tie
	0.0	Tie Closed load restored to B & C
	180.0	Crew Repairs Complex Fault
	1.0	Dispatcher Creates Switching Orders
	-	Dispatcher Closes 1 - Tests Line
	1.0	Line Holds Lock-out Resets
	10.0	Crew Travels To 2 and closes switch
	-	Faulted Area Restored Crew opens Tie

Figure 13: Initial Model Variables

Similarly, each section of the feeder was modeled for each Case. This provided us with the ability to compare the value of different levels of automation for the various cases given the same set of assumptions.

The following figure shows the results of the model for the initial assumptions.

	One time cost per feeder	Total Customer Outage Minutes per Year
Case 0	\$ -	594,000
Case 1	\$ 79,101	434,575
Case 2 (Low)	\$ 92,815	397,075
Case 2 (High)	\$ 128,415	397,075
Case 3	\$ 84,048	368,850
Case 4 (Low)	\$ 97,762	311,750
Case 4 (High)	\$ 133,362	311,750
Case 5 (Low)	\$ 107,092	261,850
Case 5 (High)	\$ 160,492	261,850
Case 6	\$ 139,265	181,580
Case 7	\$ 303,072	155,600

Figure 14: Initial Results

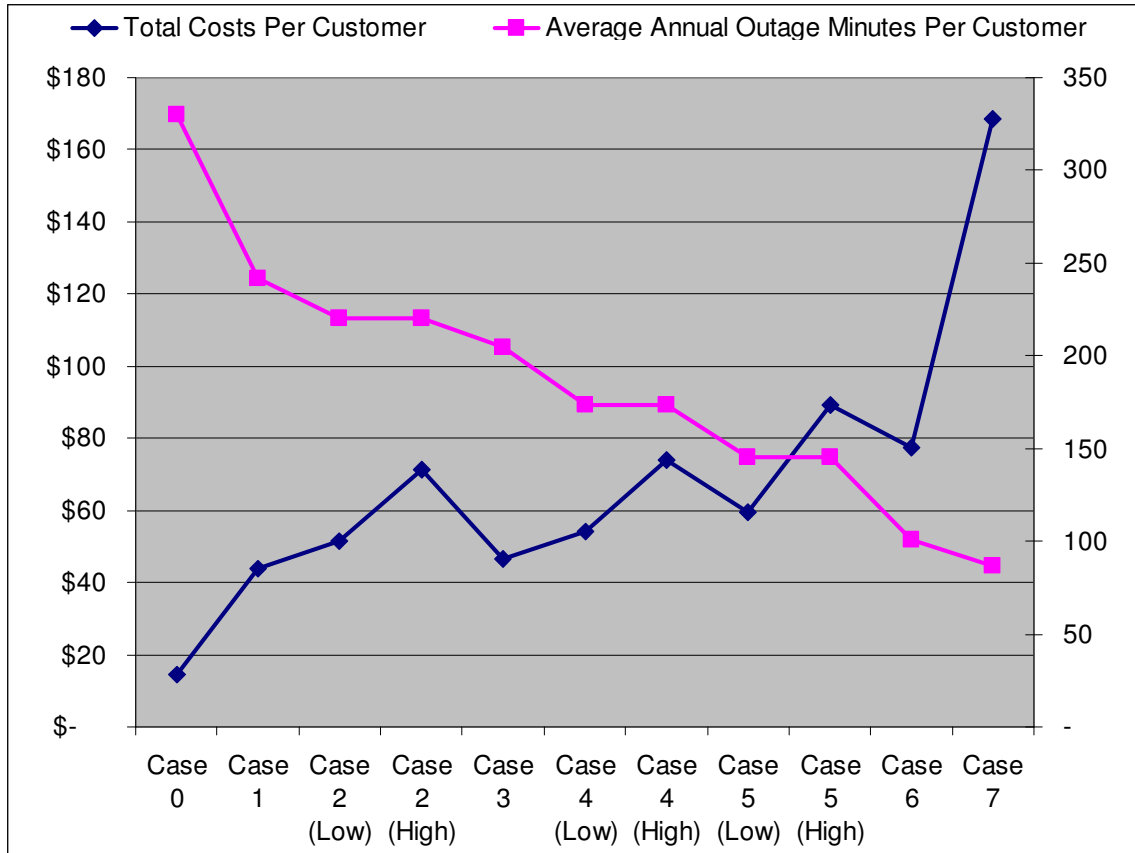


Figure 15: Cost & Benefit Graph

The figure above shows the costs and total annual customer outage minutes for each of the cases. The total cost per customer outage minute can then be calculated by dividing the two values in the previous chart.

The following is an example of how the chart can be used. For the assumption input variables entered, if the company wanted to reduce the total customer outage minutes from 600k/year to 200k/year, then the equipment on Case 6 would be required at the associated cost of about \$150k over a feeder with no switches or communication.

Sensitivity Analysis

A sensitivity analysis was performed on the various inputs to determine the sensitivity of outage times for each case to input changes. The initial analysis focused on two factors: the amplitude of changes of input to output and the deviation range of input to output.

The sensitivity analysis was performed by varying only one variable and recording a set of results for each case. The results are then stored in a matrix of outage times for each case depending on changes in the particular input.

Various statistical analyses were applied to the 11 different matrices resulting in the following table.

Variable Changed	Relative amplitude impact of changes by an input		Relative deviation range of changes by an input	
Crew Travel Time	0.24	Changes Impact results	0.04	Affects cases nearly equally
Minutes to repair Simple Faults	0.17	Moderate Impact	0.05	Affects cases nearly equally
Minutes to repair Complex Faults	0.13	Moderate Impact	0.02	Affects cases nearly equally
% Complex Faults	0.25	Moderate Impact	0.08	Affects cases nearly equally
% Alt Source Used Manual Control	0.03	Little impact	0.02	Equally affects only Cases 1-4
% Alt Source Used SCADA Control	0.17	Moderate Impact	n/a	Only applies to Case 5
% Alt Source Used ASR Control	0.26	Moderate Impact	n/a	Only applies to Case 6
Faults per Year	1.21	Significant impact	0.00	Affects cases equally
% Backbone Faults	0.56	Significant impact	0.00	Affects cases equally
Dispatcher Response Time	0.25	Moderate Impact	0.20	Primary impact on Cases 1-5

Figure 16: Sensitivity Analysis of changes to each variable

The data can be sorted and displayed graphically in the following figures. The first chart shows the variables that have the greatest impact on the output based on the amplitude of the output changes. This analysis confirms the importance of working to reduce the number of faults per year to have the greatest impact on customer outage minutes. The logic of tree trimming and maintenance practices designed to reduce distribution faults is validated by the data shown in the first chart.

The second chart is intended to show the amount of variation between the cases when changes occur in one of the inputs. This analysis showed that most of the variables had little case-to-case variation, except for the Dispatcher Busy variable. It had more than two times the variation of the other values. This means that changes in the busyness of the dispatcher will differentiate the effectiveness of one case over another.

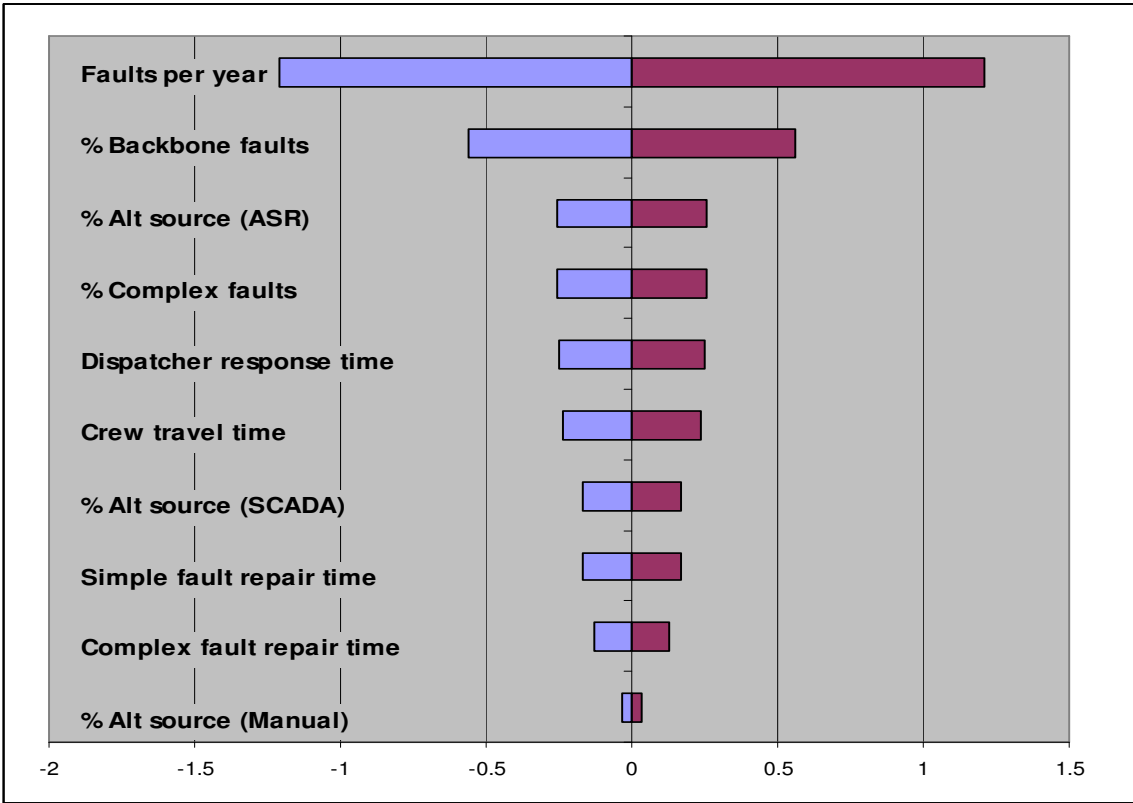


Figure 17: Relative amplitude impact of changes by each input

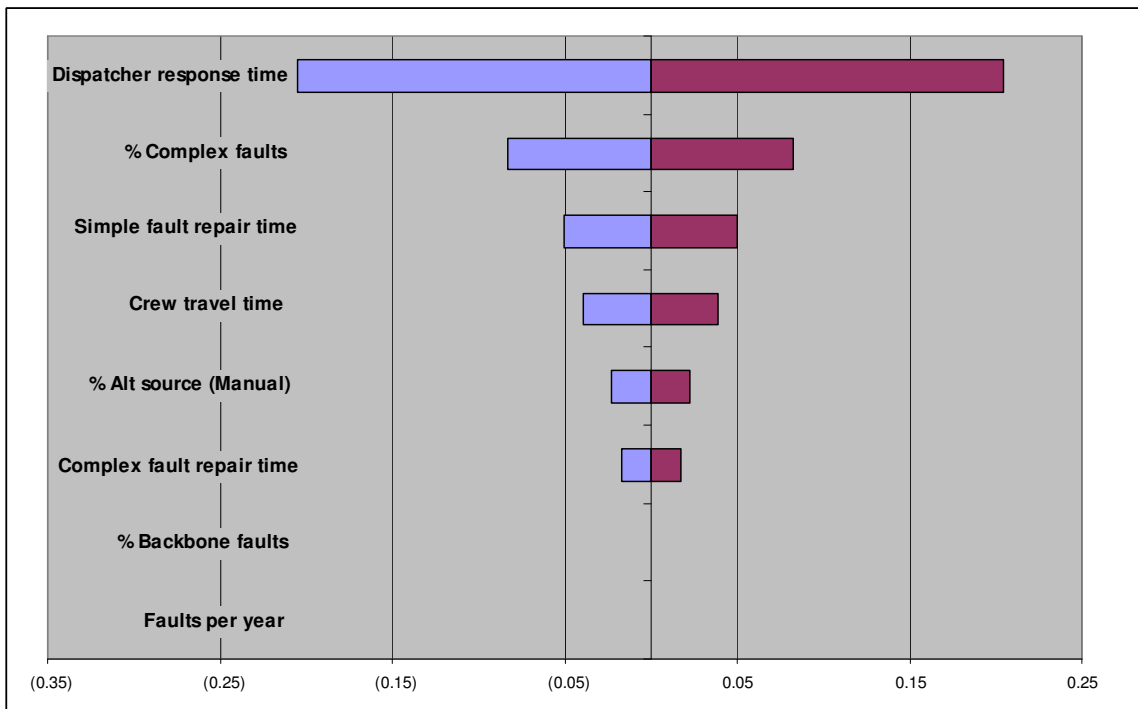


Figure 18: Relative deviation range of changes by each input

The specific details of the sensitivity analysis for dispatcher busy time are shown below. The variability impact on each case is shown by the horizontal lines with average outage times at the top of the graph. The diamonds represent the mean of the range of data for each case. It is easy to see that the variability of Case 6 and 7 is low for changes in dispatcher busy time.

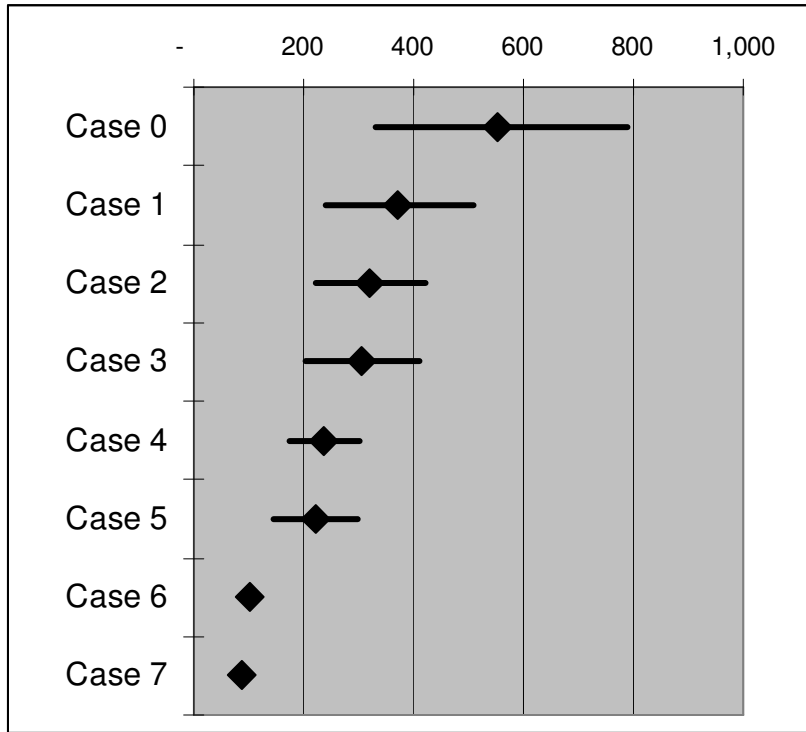


Figure 19: Relative deviation range of changes by each input

This is a significant, albeit somewhat obvious result. Dispatcher busy time does not significantly affect the automation schemes in Cases 6 or 7 because the software automatically performs the switching normally handled by the dispatcher. This difference is further illustrated by the following graph. If the Dispatcher busy time is changed from 5 minutes to 120 minutes, the results change as shown in the figure below.

The red line shows the estimated costs for each case. The blue line represents the normal curve of estimated outage minutes per customer per year. The yellow line represents the change in outage times when the dispatcher is extremely busy.

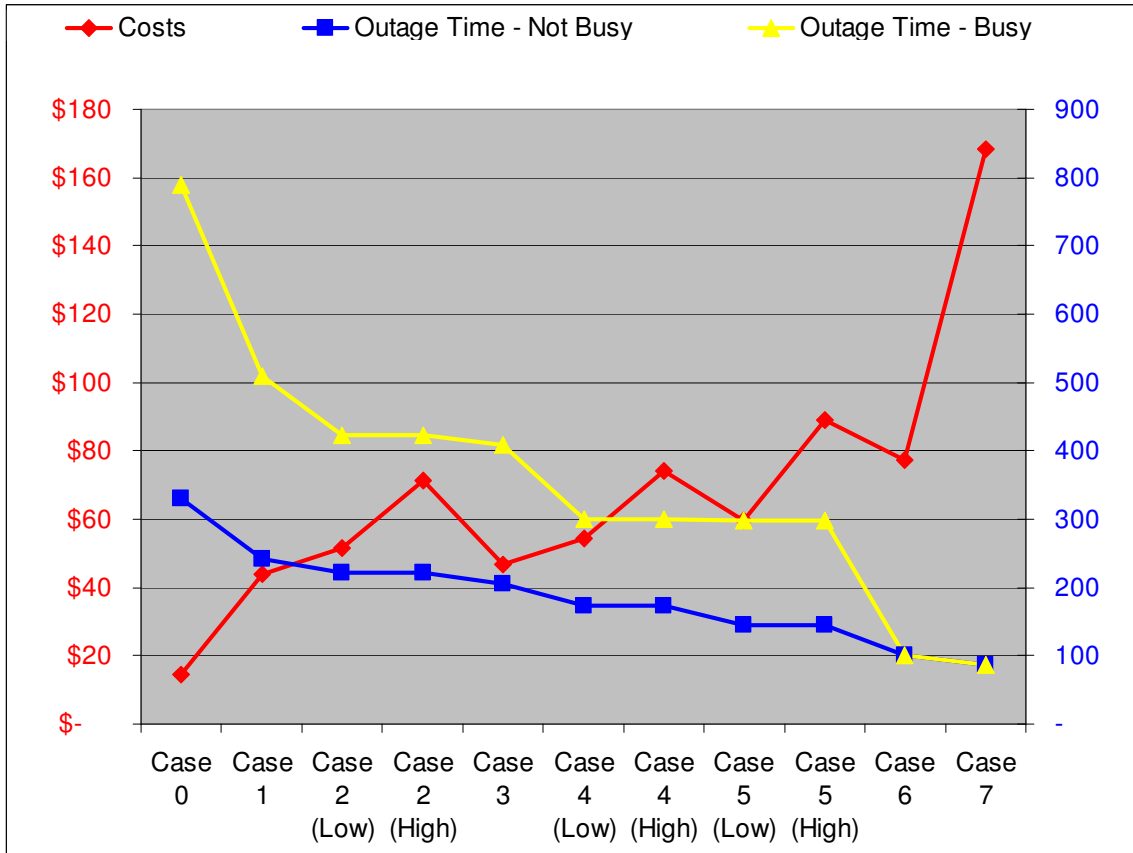


Figure 20: Cost & Benefit Graph (with two dispatch response times)

The value of the automation applied in Cases 6 and 7 is highlighted within this example. The busier the dispatcher is, the bigger the benefit of automation. In this example, the average customer outage minutes increases by about 2 times for Cases 0-5 when the dispatcher is extremely busy. The automation schemes operating in Cases 6 and 7 help the outage minutes remain nearly unchanged under either scenario because the automation operates without dispatch intervention, sectionalizing around the fault and restoring un-faulted customers within a few minutes.

VII. Challenges and Future Plans

This tool is intended to become a means to better understand and further evaluate the various levels of distribution automation available today. DA is very difficult to justify because there is no direct payback from the investment. Consequently, the importance of understanding the reduction on customer outages is even more important to determining the value of any level of automation. This analysis and the associated model, while not perfect, provide a more analytical method of decision-making.

This model and the underlying data were based on as much real world information and experience as practical. It is recommended that further validation of the model should to be conducted against a real world feeder where real before and after data has been collected.

Additionally, a few of the initial user's of the model have been concerned about the model's complexity and others have expressed problems with adapting it to fit a real, more complicated feeder with multiple ties and breakers. Balancing complexity with ease of use is a common challenge when modeling any process. It is the intent of this model to provide a tool that can be applied to a portion of the feeder or large portions of the feeder through circuit simplification.

VIII. References

1 <http://www.pepcoholdings.com/about/> Copyright © 2006 Pepco Holdings Inc.
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2 Internal PHI Document “Automation Pilot Project” Revision 00 (Final), July 23,
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