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IMPACT OF AUTOMATION ON THE RELIABILITY OF THE ATHENS UTILITIES BOARD'S DISTRIBUTION SYSTEM*

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ABSTRACT

In this paper we discuss the reliability effects of distribution automation on the Athens Utilities Board (AUB) in Athens, Tennessee. This investigation is part of the Athens Automation and Control Experiment sponsored by the U. S. Department of Energy, Office of Energy Storage and Distribution, Electric Energy Systems Program. In this experiment, distribution feeder equipment on twelve feeders connected to three substations is being remotely controlled from a central dispatch center. A supervisory control and data acquisition system provides substation and feeder monitoring and remote control of feeder circuit breakers, power reclosers, and load break switches. An analytical study is presented to show the improvement in conventional distribution system reliability indices that are achieved at AUB as a function of the penetration of automation equipment. The value of automation predicted by the study is highly sensitive to the historical outage data used in the analysis and to the economic worth of reliability assigned by the utility. These sensitivities are well known and account, at least in part, for the reluctance of some upper utility managers to invest in automation systems. Operating experience with the AUB automation system has shown that there are significant intangible reliability benefits and tangible cost savings associated with automation that are outside the scope of conventional distribution reliability indices. Eight case studies are described, from actual AUB operations, where the automation system resulted in significant cost savings and reliability benefits that are not captured by conventional reliability indices. Other utilities should expect similar benefits, which will be difficult to quantify analytically but, which add to the value of and justification for distribution automation.

1 INTRODUCTION

The Athens Automation and Control Experiment (AACE) is a large scale distribution automation research and development project being conducted on three substations and twelve feeders of the Athens Utilities Board (AUB) in Athens, Tennessee. AUB is one of 160 power distributors supplied by the Tennessee Valley Authority (TVA). The service region of AUB encompasses 100 square miles, has 10,000 customers and a peak load of 80 MW. The AACE is sponsored by the U.S. Department of Energy and managed by the Oak Ridge National Laboratory (ORNL). Supervisory control and data acquisition (SCADA) and telephone communications provide substation monitoring and control at the three substations while remote terminal units, power line carrier and telephone communication provide feeder monitoring and equipment control on the twelve feeders. Automation equipment that is particularly relevant to system reliability enhancement include substation and feeder monitoring, 12 feeder circuit breakers, 12 power reclosers, 35 load break switches and 21 fault detectors.

Automated fault detectors combined with remote control of distribution circuit breakers, power reclosers and load break switches can significantly reduce the time required to detect and locate faults, increase the speed of isolating faulted equipment and provide faster load restoration above and below a faulted feeder zone. These benefits of automation can easily be quantified using historical records and conventional reliability assessment tools such as the Predictive Reliability Assessment Model (PRAM) computer code developed under the sponsorship of EPRI [1]. In Section 2, we discuss the use of PRAM to study the improvement in distribution reliability indices achieved at AUB as a function of the number of automated switches deployed on a feeder. The value of automation is shown to be heavily dependent on the historical outage data used to establish component failure rates and on the economic worth of reliability.

After operating a distribution automation system for over thirty months, AUB has documented many instances that have increased system reliability and provided substantial cost savings to AUB that seem to fall outside of the standard indices that normally reflect system reliability. There have been several cases where AUB has been able to prevent outages or greatly reduce the outage area and number of customers affected, provide cost savings to AUB through the use of the automation system during daily and routine events that were normally performed manually, improve system safety, or detect failing equipment before a catastrophic failure of the equipment and subsequent outage. All of the above items have provided substantial dollar benefits to AUB. In Section 3 we discuss eight case studies, from actual AUB operations, which contribute to the benefit side of a cost/benefit analysis of automation but are difficult to predict and quantify in an analytical study. While each case study reflects a unique set of circumstances, and is perhaps peculiar to AUB, it is highly likely that AUB and other utilities will receive similar benefits on a continuing basis from automated operations.

Based on our experience with the automation system at AUB we conclude, in Section 4, that the value of automation in improving system reliability is understated if the value is determined solely from conventional distribution reliability assessment indices. Due to the more flexible operating environment made possible by automation, there are many opportunities for intangible reliability enhancements and tangible cost savings to be realized that are outside the scope of conventional reliability assessment studies. From the many technical conferences and other meetings that AACE project personnel have attended, it is apparent there is a large group of engineers and department supervisors that support distribution automation but have been unable to provide sufficient data to convince their managers or boards to invest in an automation system. The added benefits that AUB has been able to obtain may provide these people with the additional data needed to support their recommendations and convince upper management of the viability of distribution automation.

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2 ANALYTICAL RELIABILITY STUDIES

To quantify the effect of varying degrees of automated switching capability on the reliability of the AUB distribution system an EPRI-sponsored computer program, the Predictive Reliability Assessment Model (PRAM) [1], was used to calculate four industry-recognized reliability indices. Since automation costs are well known on the Athens system [2], it is of interest to determine the cost of incrementally improved reliability levels associated with various penetrations of automation equipment.

Using the explicit perfect protection feature in PRAM (where the protection system always functions properly), it was possible to quantify the effects of feeder protection coordination and alternative remotely-controlled feeder supplies (interties) on feeder reliability. The three feeders on AUB's South Athens Substation were analyzed: Circuit No. 7 (SA-7), Circuit No. 8 (SA-8) and Circuit No. 9 (SA-9). One line diagrams of these feeders and some of the other circuit information essential to running PRAM is given in the Appendix. SA-7 is a mixture of residential, commercial, and industrial users; SA-8 is mainly residential, having the longest lines, most customers, and least kVA load; while SA-9 is mostly industrial and commercial, having the least number of customers and greatest kVA load.

2.1 Reliability Indices

Combining a structural description of the AUB distribution feeders with remotely-controlled and manual switch operating times, line-related failure frequency data, and customer interruption duration data, PRAM calculated the load-point reliability at each load on the Athens feeders. The calculated load point results are combined by PRAM to determine the following four reliability indices for each feeder:

System Average Interruption Frequency Index

$$\mathrm{SAIFI} = \frac{\text{total number of customer interruptions}}{\text{total number of customers served}}$$

System Average Interruption Duration Index

$$\mathrm{SAIDI} = \frac{\text{sum of customer interruption durations}}{\text{total number of customers}}$$

Average Service Availability Index

$$\mathrm{ASAI} = \frac{\text{customer hours of available service}}{\text{customer hours demanded}}$$

Customer Average Interruption Duration Index

$$\mathrm{CAIDI} = \frac{\text{sum of customer interruption durations}}{\text{total number of customer interruptions}}$$

SAIDI, CAIDI, and ASAI are highly sensitive to the switching time required to sectionalize and restore service after a fault. Hence, implementing remotely-controlled switches instead of manual switches results in an improvement in these reliability measures. SAIFI is a measure of the number of outages and is not affected by the penetration of automation equipment.

2.2 Input Data Description

To analyze the three South Athens feeders, one year's worth of trouble service summaries were examined. The total number of primary circuit outages was determined on all AUB feeders and averaged over the total distribution primary circuit miles to obtain a primary circuit failure frequency of 1.53 failures/year/mile. This failure rate was assumed uniform on the three feeders involved in the study. No attempt was made to account for weather, and minor outages caused by transformer fuse openings or secondary faults were not counted. Only the effects of automation on primary line reliability were of interest.

During the course of the AACE, it was observed that restoring service using the automation equipment took, on the average, 3 minutes per switch, while manual switching requires approximately 20 minutes. Line repair generally takes 45 minutes for all but the most severe failures.

2.3 Study Scenarios and PRAM Results

Four to five automation penetration scenarios were studied for each feeder. In general, the base case (scenario 1) involves all the protection equipment and switches shown on the feeder one-line diagrams (see the Appendix) operated in a purely manual mode, that is all switching times are set to 20 minutes. The second scenario is to automate the feeder breaker such that it can be remotely reclosed after fault repair. This is accomplished in PRAM by setting the breaker switching time to 3 minutes. Subsequent scenarios involve automating a switch pair consisting of one in-line switch and one tie switch. Such a pair will allow the feeder to be sectionalized (by opening the in-line switch) and a portion of the feeder to be transferred to another feeder in order to restore load (by closing the tie). PRAM assumes that any tie switch can support any load that might be connected to it. As with the feeder breaker, the automation of the switch pair is simulated in PRAM by changing the operating time from 20 minutes to 3 minutes. Additional switch pairs are automated until the feeder's AACE design configuration is reached. Typically each feeder can be remotely sectionalized into 3 or 4 zones.

The specific automation penetration scenarios for SA-7 are:

1. base case, no automation
2. automate the feeder breaker BR244
3. automate BR244 and switch pair SW14 and SW43 (two zones)
4. automate BR244, SW14, SW43, SW70 and SW126 (three zones)
5. automate BR244, SW14, SW43, SW70, SW126, SW207 and SW15 (four zones)

Four automation cases are defined for SA-8:

1. no automation
2. automate BR234
3. automate BR234, recloser RCL117 and SW16 (two zones)
4. automate BR234, RCL117, SW16, SW20 and SW15 (three zones)

Finally, the cases studied for SA-9 are:

1. no automation
2. automate BR214
3. automate BR214, SW170 and SW180 (two zones)
4. automate BR214, SW170, SW180 and RCL226 (three zones)

For each feeder and automation case above, four combinations of manual switching time and line failure rate were investigated with PRAM. These combinations are:

A. 20 minutes, 1.53 failures/year/mile (the nominal values)

B. 40 minutes, 1.53 failures/year/mile (high switching time)

C. 20 minutes, 0.765 failures/year/mile (low failure rate)

D. 20 minutes, 3.06 failures/year/mile (high failure rate)

The reliability calculations are contained in Figures 1, 2, and 3 for SA-7, SA-8, and SA-9 respectively. The figures confirm the

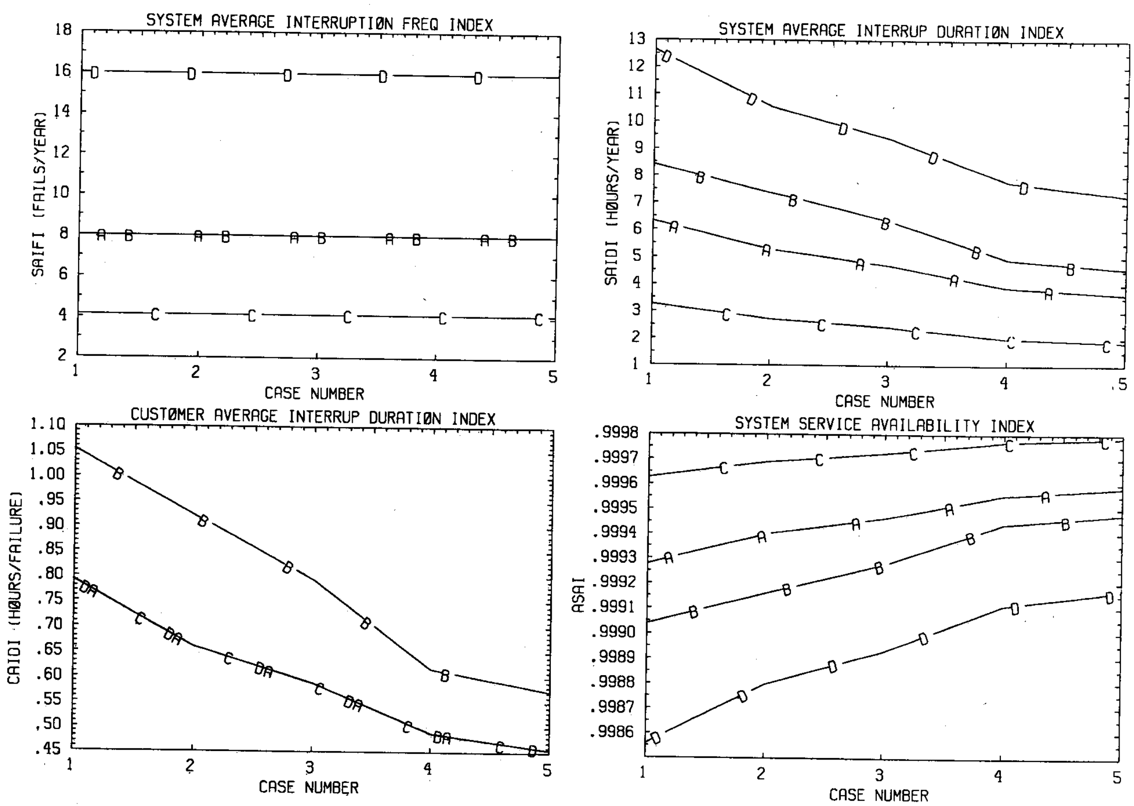

Figure 1: Reliability Assessment of South Athens Circuit #7 for increasing levels of automation.

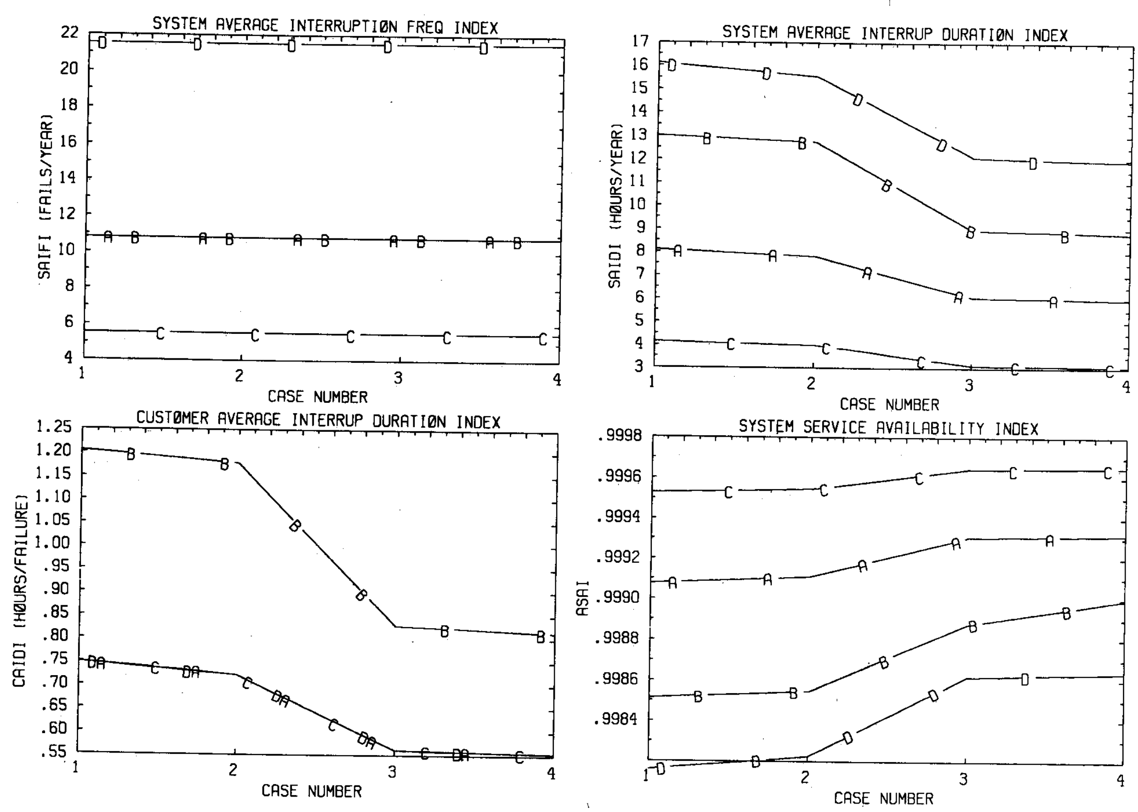

Figure 2: Reliability Assessment of South Athens Circuit #8 for increasing levels of automation.

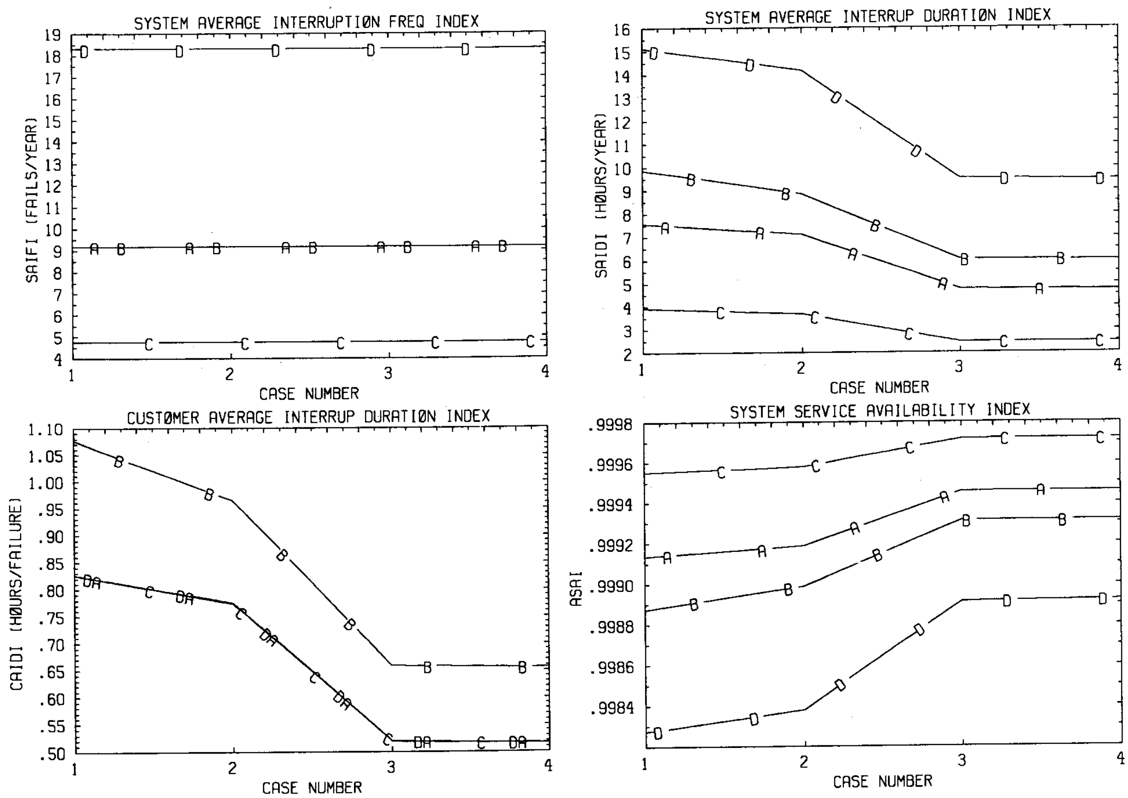

Figure 3: Reliability Assessment of South Athens Circuit #9 for increasing levels of automation.

expected improvement in distribution reliability from automation. All of the indices monotonically improve as additional automation is added but tend to flatten out when enough automation is added to have one automated in-line switch and one automated tie switch on each major branch of the feeder. The flattening of the curves suggests that a point of diminishing returns may be reached where adding more automated switching capability provides little or no benefit. Benefit/cost analysis is described below.

2.4 Example Cost/Benefit Analysis

To conduct a cost/benefit analysis for the impact of automation on distribution system reliability requires three factors: the cost of automation equipment, quantifying the improvement in reliability through automation, and specification of the worth of reliability. While the cost of automation is well documented for the AACE [2] and the impact of automation on reliability indices is easily assessed using an analytical tool such as PRAM, the worth of reliability is highly controversial. Numerous studies have been conducted and published values on the worth of reliability, or equivalently the cost of outages, vary greatly. A summary of outage cost studies can be found in [3].

Table 1, from [2], shows the incremental cost of the automation equipment installed on SA-9. Using the table, the equipment cost for scenario 2 (automate BR214) is $10,232, for scenario 3 (automate BR214, SW170, and SW180) is $34,972, while the cost of scenario 4 (automate BR214, SW170, SW180, and RCL226) is $41,592.

We have not attempted to accurately determine the cost of outages for customers at AUB. Such costs would likely be as controversial as other published data and at best applicable only to the Athens Utilities Board. It is generally acknowledged that the cost of outages are highest in the industrial sector, although cost estimates still vary widely.

Table 1: Remote switch and recloser cost

	Material Cost	Labor (hrs)	Total (@$35/hr)
BR214 (feeder circuit breaker) automated switching with status indication and three phase monitoring	$3,337	197	$10,232
SW180 (tie switch) automated load/break switch with status indication	$6,500	51	$8,285
SW170 (in-line switch) automated load/break switch with status indication and three phase monitoring	$11,100	153	$16,455
RCL226 automated switching and status indication (w/o recloser cost)	$3,750	82	$6,620

In order to demonstrate cost/benefit analysis we will use the short duration (1 hour) outage cost data for the industrial sector given by SRI in [3] to analyze SA-9. According to [3], the average outage cost for an industrial customer in the U.S. is $6.56/kWh with extremes of $3.21/kWh and $14.46/kWh (all in 1977 dollars). Using the consumer price index [4] in 1986 (3.284) and 1977 (1.815) to adjust these costs to 1986 dollars and assuming an average load of

6,000 kW on SA-9 (1986 kWh sales were 52,621,320), low, average, and high estimates of the yearly outage cost to customers on SA-9 (in 1986 dollars) are given by

$$5.81 \times \text{SAIDI} \times 6,000$$

$$11.87 \times \text{SAIDI} \times 6,000$$

and

$$26.16 \times \text{SAIDI} \times 6,000$$

respectively. Using these expressions and the cost data from Table 1 yields the cost/benefit analysis shown in Table 2 for 1.53 failures/year/mile, manual switching time of 20 minutes and automated switching time of 3 minutes.

The table shows that even if we assume the lowest outage cost ($5.81/kWh) the automated cases appear to be fully justified on this feeder by the avoided customer outage cost. However the equipment costs in the table represent only the incremental cost of added switching capability; they do not account for the basic system cost including SCADA and communications systems. While this example illustrates some key points, a comprehensive analysis should include the total annualized automation costs.

Note that the customer outage cost given above are linear in SAIDI which is in turn heavily dependent on the historical outage frequency. If the failures/year/mile is halved to 0.765 (with manual switching times of 20 minutes and automated switching at 3 minutes) then the cost/benefit table for SA-9 is that shown in Table 3 which clearly shows that the benefits of automation on reliability decreases with outage frequency. This result highlights the importance of using accurate historical outage data in making cost/benefit studies.

Since outage cost on residential and commercial circuits are lower than for industrial circuits, a similar cost/benefit analysis for SA-7 and SA-8 would naturally show lower benefits of automation than on SA-9. However, the community hospital in Athens is connected to SA-7 and the outage cost could be assigned a value high enough to justify extensive automation to improve the reliability of that

Table 2: Cost/Benefit for SA-9 assuming 1.53 failures/year/mile, 20 minutes for manual switching time, 3 minutes for automated switching time and 6,000 kW average load for one year

	STUDY CASE	OUTAGE COST in 1986 dollars			RELIABILITY BENEFITS OF AUTOMATION in 1986 dollars		
		low	average	high	low	average	high
1	Base Case No Automation SAIDI = 7.58	264,239	539,848	1,189,757			
2	Automate BR214 cost = $10,232 SAIDI = 7.11	247,855	506,374	1,115,986	16,384	33,474	73,771
3	Automate BR214 SW170 and SW180 cost = $34,972 SAIDI = 4.77	166,282	339,719	748,699	97,957	200,129	441,058
4	Automate BR214, SW170, SW180 and RCL226 cost = $41,592 SAIDI = 4.74	165,236	337,583	743,990	99,003	202,265	445,767

Table 3: Cost/Benefit for SA-9 assuming 0.765 failures/year/mile, 20 minutes for manual switching time, 3 minutes for automated switching time and 6,000 kW average load for one year

	STUDY CASE	OUTAGE COST in 1986 dollars			RELIABILITY BENEFITS OF AUTOMATION in 1986 dollars		
		low	average	high	low	average	high
1	Base Case No Automation SAIDI = 3.93	137,000	279,895	616,853			
2	Automate BR214 cost = $10,232 SAIDI = 3.68	128,285	262,090	577,613	8,715	17,805	39,240
3	Automate BR214 SW 170 and SW180 cost=$34,972 SAIDI = 2.47	86,104	175,913	387,691	50,896	103,982	229,162
4	Automate BR214, SW170, SW180 and RCL226 cost=$41,592 SAIDI = 2.46	85,756	175,201	386,122	51,244	104,694	230,731

circuit. AUB has, in fact, realized public relations benefits due to the improved reliability of service to the hospital resulting from the automation installed as part of the AACE.

In summary, cost/benefit assessments to justify reliability enhancement through automation are conceptually straightforward. Such studies require accurate historical outage frequency data and an appropriate value for the worth of reliability. Since the worth of reliability is controversial, justification for automation based on reliability cost/benefit analysis will also be controversial.

After operating its automation system for thirty months, AUB has encountered many instances in which the automation system has provided intangible reliability benefits (in the sense that the benefits do not appear to be captured in standard reliability indices) with significant cost savings to AUB. Eight such instances are discussed below.

3 CASE STUDIES

The automation system at AUB was installed and tested over a thirty month period; January, 1985 to June, 1987. During this interval, AUB personnel have gained confidence in the automation system and its value in system operations, especially with regard to its use in diagnosing and resolving system problems before they escalate into serious outages. Eight specific cases are described below along with estimated cost savings to AUB.

Case 1: Prevention of a Load Tap Changing Transformer Failure

Most utilities make and record periodic readings of breaker, switch, and tap changer counters. These readings are taken weekly at AUB (time permitting) and are used for general maintenance information and to check against trouble reports. Typically, it takes several weeks before a trend towards increased operations can be detected. However, AUB's console operators were able to observe a substantial increase in the frequency of tap changer operations on both load tap changing (LTC) transformers at AUB's South Athens Substation. They reported that the LTCs were jumping two, three, and four steps at a time and then back again. On several occasions, two or three raise or lower commands were required to produce a one step change in tap position. A crew was dispatched to investigate. What the maintenance crew observed on site verified the operators' findings. Further investigation revealed an extraordinary increase in counter readings between the last reading and the current reading. Historically, these tap changers averaged 20 operations a day, but for the six days between readings, the operation count averaged over 200 per day. At this point, it was decided to lock out the tap changers and check the unit completely.

The results of subsequent overhaul showed that one of the LTC sensing units was out of calibration resulting in frequent tap changes. Since the two transformers are connected in parallel, the healthy LTC hunted the malfunctioning LTC so as to stay within two steps of it. Both seal-in relays that ensure that the tap changers advance a full step were faulty, and as a result, all contacts on the tap changers were damaged to the point of failure. The cost of repairs to the transformers was $24,000 as compared to $250,000 for the replacement of major LTC components, lost revenue, and labor costs. This represents a potential avoided cost of 226,000.

Case 2: Complex Maintenance Operation

The repair of the tap changers required AUB to transfer, on three successive nights, all of the load on the South Athens Substation to the North Athens Substation. This presented a unique opportunity to quantify the benefits of the automation system. In order to transfer the South Athens load to North Athens, one set of line regulators had to be set to their nominal tap position and nine distribution switches operated. The first night this transfer was done without the use of the automation system. Twelve linemen, two supervisors, and one dispatcher were involved in the operation. Nine linemen were involved in manually transferring the load, five of them returned to the substation to assist in repairs. The first night required 27 minutes to disconnect the first transformer and 2 hours and 13 minutes to manually execute all switching. After completion of work in the substation, the five men involved earlier in the load transfer returned to the field to retransfer the load to the South Athens substation. The total event duration was two hours and forty minutes, requiring 15 men (forty manhours).

Table 4: AUB load transfer times

	Night 1 manual	Night 2 automated	Night 3 automated
Total duration	2:40	1:48	1:16
Switching time	2:13	1:20	0:44
Man-hours required	40.00	18.00	10.13
Workmen dispatched	15	10	8

The following two nights the load transfer was accomplished with the use of the automation system. Table 4 shows the reduction in manpower required as confidence was gained in the automation system. Manpower was reduced from the original fifteen men to ten to eight, and manhours from 40 to 18 to 10.13. The reduction in manpower requirements resulted in a labor savings of 51.9 man-hours for the work on the second two nights ($1,945 assuming $37.5 per man-hour for overtime work).

AUB has made this same load transfer on two subsequent occasions to repair bus current transformers damaged by lightning. Fully automated switching times have been further reduced to 18 minutes and 12 minutes. Assuming that manual switching requires 2 hours and 13 minutes and 7 additional people, the labor savings on these two operations was 27.5 man-hours ($1,033).

Case 3: Detection of a Capacitor Bank Failure

In October 1986, the Tennessee Valley Authority raised its power factor billing requirement from .85 lagging on peak to .93 and added an off peak factor of .97 leading. As a result, many TVA distributors have installed var controlled capacitor banks to increase power factor and avoid these penalties. However, some distributors have had problems in determining proper locations for the banks, along with problems in detecting defective capacitors and controllers. By measuring real and reactive power flows, the automated feeder monitoring system at AUB has helped indicate where banks should be placed. In addition, the monitoring system has prevented two outages on the North Athens Substation by alarming neutral currents that were 95% of the trip value at the substation. In response to each of these alarms, operators surveyed power flow data and were able to pinpoint two capacitor banks which appeared to have one open phase. By remotely operating these banks and observing var flows, this suspicion was confirmed. The prevention of these two outages resulted in a cost avoidance to AUB of $3,500 ($1,800 labor and $1,700 lost revenue).

Case 4: Detection of a Tap Changer Failure in a Line Regulator

The detection of a runaway tap changer motor in a line regulator resulted in prevention of an outage and destruction of the regulator. Cost avoidance to AUB is estimated to be $6,100 ($5,000 cost of regulator, $800 lost revenue, $300 labor costs).

Case 5: Industrial Accident

An industrial customer called AUB to report that during roof repairs a strip of metal had fallen off the roof into their power transformers and had damaged their secondary leads such that the conductors were burning. Primary conductors were damaged and getting hot. AUB was able to immediately transfer half of the circuit to another feeder, open the reclosing relay cut-out switch to the feeder breaker, and open a sectionalizing switch near the plant to de-energize the transformers. AUB removed the jumpers to the transformers and the sectionalizing switch was closed, 10 minutes after it was opened.

AUB was able to prevent an outage to 90 percent of the customers on that feeder, and the remaining ten percent were out of service for only ten minutes. The cost avoidance to AUB is estimated at $4,200 ($4,000 cost of transformer, $200 lost revenue).

Case 6: Automated Blocking of Circuit Breaker Reclosure

The reclosing relay in a feeder breaker or distribution power recloser serves to automatically reclose the breaker or recloser a specific number of times before locking out the interrupter due to a fault. The reclosing relay cut-out switch is opened to prevent the breaker from reclosing when switching is performed to transfer load, when linemen are working, or for various other reasons. Over the past two and a half years, AUB has averaged one operation per day of a reclosing relay cut-out switch by remote operation. The ability to remotely operate reclosing relay cut-out switches has enabled AUB to reduce outage times, increase productivity, reduce labor costs, and increase system and personnel safety. Each manual operation of a reclosing relay cut-out switch requires about 0.5 man-hour. Assuming one such operation per day, at $25 per man-hour, the labor costs savings to AUB over the last 30 months are estimated at $11,406 (1/1/85 through 6/30/87).

Case 7: Detection of an Abnormal Load Condition

Starting in June of 1987, just after 1:00 pm on weekdays, high current alarms on one of AUB's feeders were reported by the automation system. The high current readings lasted only a few minutes and then dropped below alarm limits. Since the duration was short, ammeters in the breakers could not verify this behavior. Calibration of the watt/var and voltage transducers in the breaker was checked and and found to be within tolerance. As a result, AUB studied all monitored data and focused in on a specific location on the feeder. It was found that two industrial customers, that had recently expanded operations, were creating a needle peak for about five minutes during their afternoon start-up. Current levels at the breaker were running at a value of 98% of relay pickup during this short time. This type of needle peak could not have been detected so quickly without the automation system. Several circuit breaker operations, and at least one outage, would likely have occurred before AUB would have been able to determine the exact nature of the problem. As a result, AUB determined a more optimum feeder configuration and remotely reconfigured the distribution system. Cost avoidance to AUB is estimated at $1,800 ($1,000 lost revenue, $800 labor cost). However, it must be pointed out that this particular feeder (South Athens Circuit No. 9) has mainly commercial and industrial loads. Interviews of the plant managers and store operators indicate that a one hour outage is extremely expensive to them. One customer alone would lose $10,000 due to a half hour outage.

Case 8: Insulator Failure

Early in the morning on two consecutive days, the automation system recorded instantaneous operation on one of AUB's circuits. Of particular concern was a hospital located on this feeder. AUB decided to switch the hospital to another feeder and transfer two other sections to other feeders in hopes of narrowing down the area which was causing the breaker to operate. Three days later, another operation was detected on the same circuit. AUB was able to narrow its search area to a half mile section of line. A failing insulator was found and it was replaced before it caused an outage. AUB was then able to transfer the hospital, a large shopping center, and a commercial sector back to a more stable and reliable circuit. The cost avoidance to AUB was estimated at $400 ($300 lost revenue, $100 labor costs).

The eight case studies discussed above are representative of the intangible reliability benefits and cost savings that have been achieved at AUB through automation. There are many additional instances which could be documented.

4 CONCLUSIONS

The AUB distribution system is fairly typical of many distribution systems across the country. There are no outstanding characteristics that make AUB field operations different from other utilities, and hence, there is reason to believe that other utilities would realize operational benefits similar to those that AUB has achieved with its automation system.

ORNL and AUB have been able to show that system reliability has increased due to automation, based on standard reliability measurement indices. However, it has also been shown that events take place, outside the realm of these standard indices, that produce substantial cost savings to the utility. The case studies presented show a direct benefit to AUB of $256,384 over a period of 30 months. These savings could not have been predicted by analytical studies, and as time goes on, other cost savings will add to the total. Many of the major benefits of an automation system result from the diagnostic ability to prevent small problems and outages from escalating into large outages. Using analytical techniques to justify automation from an improved reliability standpoint clearly requires accurate historical outage data and careful use of advanced reliability evaluation models. At best, the cost/benefit conclusions resulting from such a study are tenuous in the absence of good "worth of reliability" data.

POSTSCRIPT

There is one case study that was not discussed because one cannot tie a cost savings to it. On July 29, 1987, at 3:28 pm, the automation system reported two operations of the feeder circuit breaker on North Athens Circuit 2. A supervisor was at the console at the time and received a call from a customer at 3:30 pm reporting that a truck had run into a power pole in her front yard. Lines were down across the truck and were "burning and sparking everywhere". The driver was trapped inside. The breaker had reclosed on the fault. At 3:30:56, the supervisor remotely opened the breaker, de-energizing the circuit. The driver safely left the vehicle. The automation system may or may not have saved his life, but one resident in Athens is extremely grateful it was there.

References

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[3] *The National Electric Reliability Study: Technical study reports, DOE1EP-0005*, April 1981, Appendix B, p. 525.

[4] *Survey of Current Business*, Bureau of Economic Analysis, U. S. Department of Commerce, Washington, D. C.

APPENDIX

One line diagrams of SA-7, SA-8, and SA-9 are given in Figures A1, A2, and A3 respectively.

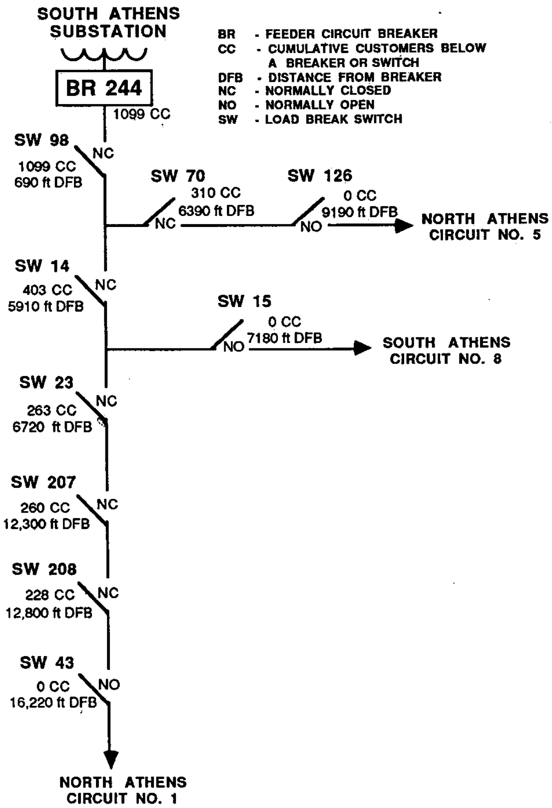


Figure A1: One line diagram of South Athens Circuit No. #7.

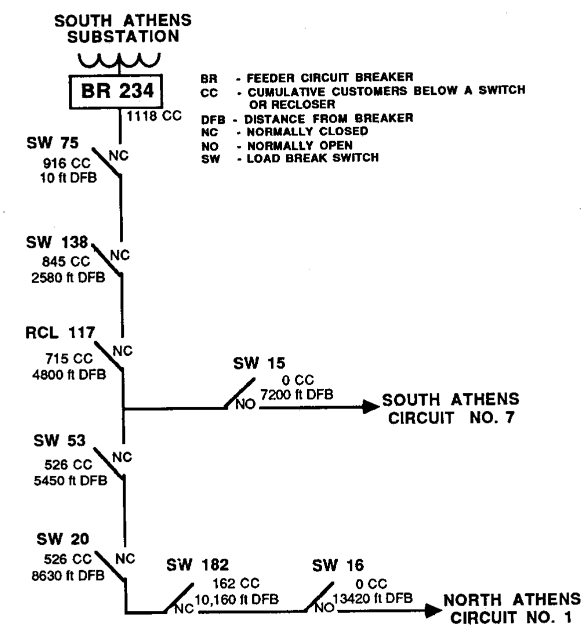


Figure A2: One line diagram of South Athens Circuit No. #8.

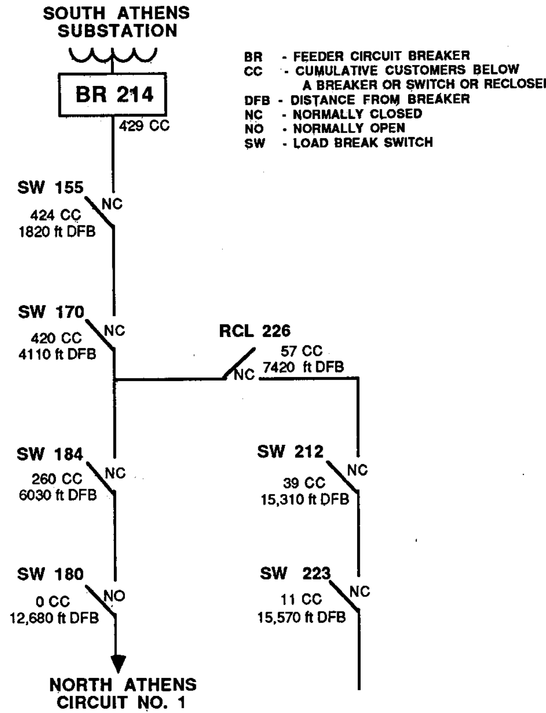
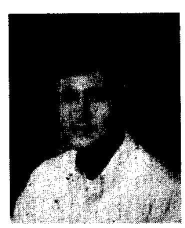
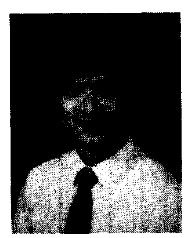


Figure A3: One-line diagram of South Athens Circuit No. #9.

BIOGRAPHIES



J. S. Lawler (S'77-M'79) is an Associate Professor of Electrical Engineering specializing in electric power systems. He received the Ph.D in Systems Science from Michigan State University in 1979 and has been with the University of Tennessee since graduation. His active research interests include automation of electric distribution systems and power electronics circuits and controls. Dr. Lawler is a member of IEEE, Phi Kappa Phi and Sigma Xi.

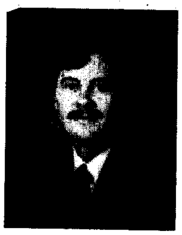


Jih-Sheng Lai (S'84) was born in Taichung, Taiwan, in 1953. He received a B.Ed. and M.Ed. from National Taiwan Normal University and MSEE from the University of Tennessee, Knoxville, in 1975, 1980, and 1985, respectively. He is currently working on a Ph.D. at the University of Tennessee, Knoxville.

From 1980 to 1983 he was Instructor and Chairman of the Department of Electrical Engineering at Ming-Chi Institute of Technology, Taipei, Taiwan. He served as an Instructor in the Department of Electrical and Computer Engineering at the University of Tennessee, Knoxville from 1986 to 1987. He is now a research assistant in a joint program established by the University of Tennessee and the Power Electronics Applications Center. His research interests are computer applications in modern control systems, power systems, and power electronics motor drives.

Mr. Lai is a student member of IEEE, and a member of Phi Kappa Phi.

L. D. Monteen (M'87) was born in Kenosha, Wisconsin on January 25, 1951. He received a BSEE degree in 1973 and and an MSEE in 1977 from Tennessee Technological University, Cookeville, Tennessee and completed course work for a doctorate degree at the University of Tennessee, Knoxville, Tennessee in 1980. Mr. Monteen has over 45 continuing education units in various areas. He has worked as an industrial engineer for the American Motors Corp. (1970-71), a graduate assistant for the Tennessee Technological University (1973-77) and the University of Tennessee (1977-1980), a project engineer for the Naval Air Systems Command Mine Hunting Branch (1974-1975), and project manager for the Athens Utilities Board for the Athens Utilities Board for the Athens Automation and Control Experiment (1980 to Present). He is a member of the IEEE Distribution Automation Working Group and the APPA Communications and Control Committee.



J. B. Patton (S'73, M'75) received a Bachelor's degree from the University of Colorado in 1975 and a Master's degree from Rensselaer Polytechnic Institute in 1976. He worked as a field engineer for General Electric before joining Systems Control of Palo Alto, CA in 1979. While at SC, Mr. Patton investigated dispersed generation interconnection protection and distribution automation benefits. In 1982, Mr. Patton became an independent consultant, working primarily on the Athens Automation and Control Experiment. He is the author of the SYSRAP distribution automation application software.

D. Thomas Rizy (S'76, M'77, M'84) was born in Hartford, Connecticut and received a BSEE degree from the University of Virginia, Charlottesville, Virginia in 1976 and an MSEE degree in Power Systems from the Virginia Polytechnic Institute, Blacksburg, Virginia in 1977. He has worked for the Oak Ridge National Laboratory located in Oak Ridge, Tennessee in the Energy Division since 1978 and his research activities have involved load management, distribution system protection, and distribution system automation. Presently, Mr. Rizy is the technical leader for the volt/var control experiments being conducted as part of the Athens Automation and Control Experiment, a large distribution automation research project sponsored by the Department of Energy. He is a member of the IEEE Working Group on Distribution Automation and the IEEE Standards Coordinating Committee on Dispersed Storage and Generation.