Plan Ahead for Substation Automation

by Steve Haacke, Sam Border, Dehn Stevens, and Bob Uluski

Building a business case ensures that costs and benefits, both monetary and strategic, are well understood ahead of time and are supportive of company business drivers.

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TECHNOLOGICAL IMPROVEMENTS TO INTELLIGENT ELECTRONIC DEVICES (IEDs) and the communication facilities and protocols that enable their integration are occurring at a rapid pace. To ensure that ongoing internal efforts to integrate the IEDs has proper direction given industry developments, MidAmerican Energy Company developed a substation automation (SA) plan and is in the process of implementing it at two pilot substations.

Before proceeding with system implementation activities, MidAmerican elected to develop a business case to ensure that the operational and strategic benefits that would be achieved and the costs to achieve these benefits were well understood ahead of time. Lack of a solid business case has always been one of the leading obstacles to the successful implementation of electric utility automation projects. Building a business case for the automation project will ensure that the costs and the benefits, both monetary and strategic, are well understood ahead of time and are supportive of company business drivers.

This article describes the methodology used to develop the business case for expanding the implementation of SA technologies at MidAmerican's substations and summarizes the results of this analysis.

MidAmerican's Goals and Objectives

MidAmerican Energy Company is the largest utility in Iowa, providing service to more than 668,000 electricity customers in a 10,600 square-mile area from Sioux City, Iowa, to the Quad Cities area of Iowa and Illinois. The largest communities served by MidAmerican are Des Moines, Sioux City, Waterloo, Iowa City, and Council Bluffs, Iowa, and the Quad Cities area of Iowa and Illinois. Figure 1 shows MidAmerican's service territory.

MidAmerican meets the needs of its electric customers with more than 4,400 MW of generating capability. Their record peak load was 3,833 MW, set in July 1999.

MidAmerican's primary goal for its substation automation facilities is to develop an integrated approach for implementing SA systems in a cost-effective manner that will enable corporate personnel to exploit the wealth of information that is available in IEDs that are being installed in MidAmerican substations. The overall objective of the study was to determine what additional functionality changes, if any, to MidAmerican's current standard approach to substation monitoring and control architecture are justified to accomplish the primary goal.

The specific objectives of the study are threefold:

- identify additional SA functions that produce significant operational benefits
- determine the economic justification for implementing some or all of these functions using benefit-cost analysis
- determine what architecture should be used to implement cost-justified application functions (enhanced RTU-centered approach versus distributed LAN approach).

This article focuses on two of these objectives: the identification and cost justification of additional SA functions.

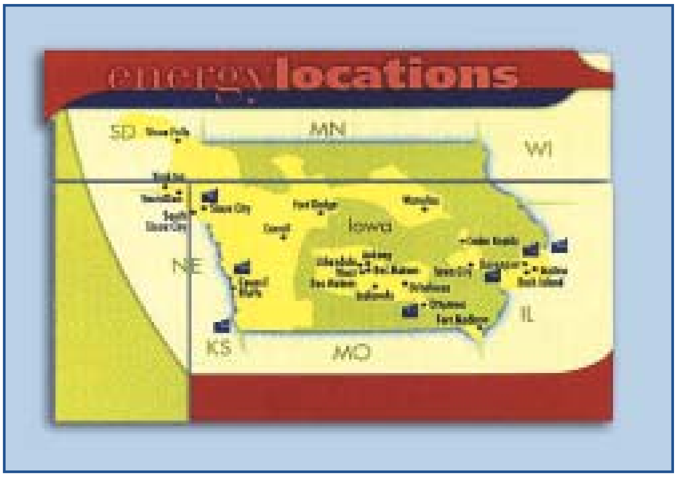

figure 1. MidAmerican service territory.

> Effective SA systems address the company's most significant business problems today while providing the ability to add future functionality when needed.

Methodology for Developing a Business Case

There are three main parts to the methodology:

- ✔ information exchange
- ✔ benefit-cost analysis
- ✔ presentation of results.

Figure 2 depicts the methodology used to develop the SA business case. Key activities performed in each part of the process are described as follows.

Information Exchange

Gathering information needed to perform this study is a two-part process, consisting of interviews with senior management personnel followed by interviews with representatives of operating groups impacted by the SA system. The results of these interviews were then documented, and a list of "candidate" SA functions was prepared. Each of these activities is briefly described as follows.

Management Interviews

The most effective SA system is one that addresses the company's most significant business problems today while providing the ability to add future functionality when needed. An important step in determining the SA functionality is to identify the business problems experienced by key individuals who "own" the problems. The SA system characteristics will attempt to alleviate and/or solve these business problems. As the first step in this process, senior management officials were interviewed to obtain a broad assessment of the major business problems faced by MidAmerican, along with their vision and future plans for the company.

One of the most important results of the management interviews was a list of business "drivers" to be addressed in the SA business case. MidAmerican's key business drivers pertaining to SA are:

- ✔ reliability and quality of service
- ✔ customer loyalty
- ✔ cost of service
- ✔ deliverance of information to the enterprise
- ✔ proactive response to industry developments.

Departmental Interviews

Managers and representatives of departments responsible for planning, designing, constructing, operating, maintaining, and marketing MidAmerican's power system were interviewed as the next step in identifying operating problems and needs that should be considered in the evaluation of substation automation opportunities. Current automation facilities and their limitations, desired improvements, and future plans were also discussed. In addition, information needed to perform the benefit-cost analysis was collected.

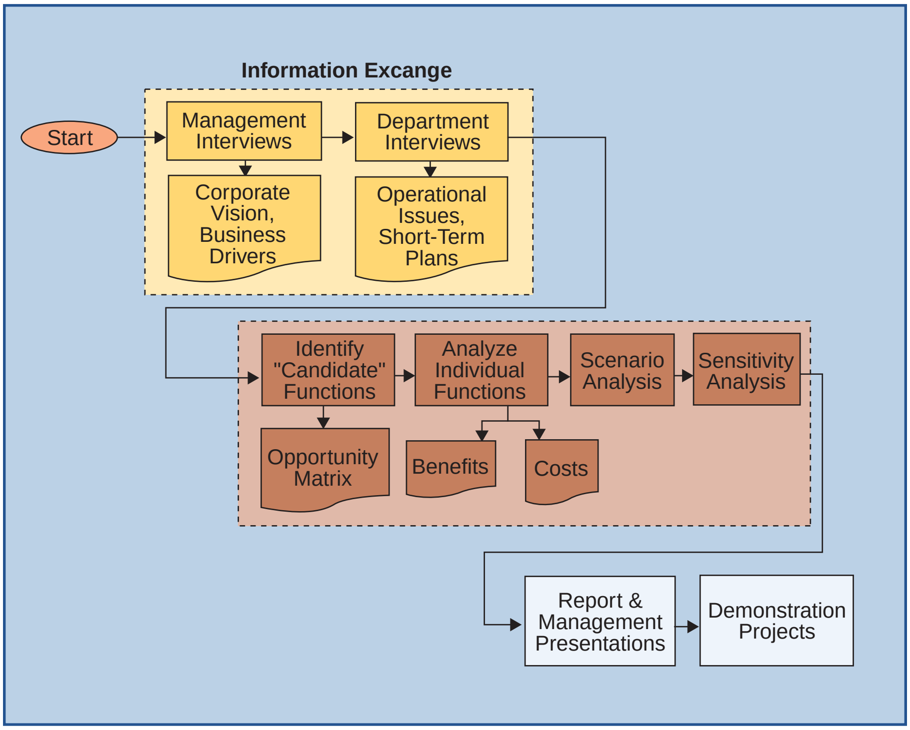

figure 2. Business case methodology.

Candidate SA Functions

Following the completion of interviews, a list of candidate functions was prepared. These are the SA functions that appear to provide solutions to table 1. Opportunity matrix.

SA Function	Business Drivers				
	Service Quality	Customer Loyalty	Cost of Service	Enterprise Information	Proactive Response
Equipment condition monitoring	✓		✓		✓
Automatic load restoration	✓		✓		✓
Dynamic transformer ratings	✓		✓		
Adaptive relay settings for distribution circuits	✓				✓
Power system disturbance and power quality data	✓				✓
Feeder automation support	✓		✓		✓
Expert alarm processing	✓				
Access to Substation Metering Data		✓		✓	✓
Access to MidAmerican documents and systems				✓	
Corporate data repository				✓	
Additional SCADA quantities	✓			✓	
Adding SCADA to non-SCADA substations	✓		✓		
Training simulator	✓		✓		

MidAmerican's business problems and needs identified during the interviews. Table 1 is an opportunity matrix listing the candidate functions along with the expected benefits. Detailed benefit-cost analysis was performed on these potential SA functions.

Benefit-Cost Analysis

All new SA functions must be economically justified. Only those SA functions that have incremental monetary and strategic benefits that outweigh the incremental cost to implement the function should be implemented. A benefit-cost analysis was performed to determine which of the candidate SA functions identified during the information-exchange process is economically justified. The benefit-cost analysis procedure is summarized as follows.

Compute Incremental Benefits and Costs for Each Candidate Function

Incremental, "hard" benefits were calculated for each individual candidate SA function. *Incremental benefits* are benefits that cannot be achieved using the existing complement of hardware and software. (For example, the SA system cannot be credited with construction cost savings due to reduced control panel size, because MidAmerican has already achieved this benefit by using IEDs in its substations.) *Hard benefits* are those benefits that produce actual dollar savings to MidAmerican. Hard benefits include:

- reduction of electrical losses
- reduction of power supply demand charges
- labor savings (reduction in overtime or contract labor costs)
- elimination or postponement of capital expenditures
- savings in construction costs
- reduction in operating and maintenance (O&M) costs for power system equipment.

Incremental costs to implement each individual candidate function were calculated. *Incremental cost* is the additional expenditure needed to incorporate the candidate function on the SA system platform. Costs to purchase, implement, and maintain each function were included. One-time costs (such as equipment purchase and installation) were converted to equivalent levelized annual expenditures to support the analysis of revenue requirements.

Handling of Reliability Improvement Benefits

Improving the reliability of the electric system is one of MidAmerican's most important business drivers. However, direct monetary benefits assignable to reductions in outage duration and frequency are small. Since MidAmerican is not presently subject to performance-based rates (which can result in significant monetary benefits), the monetary benefits associated with reliability improvement are limited to the reduction of lost revenue due to kilowatt-hour sales and labor savings by employing automated rather than manual switching, both of which are typically very small dollar amounts.

To quantify the benefits of reliability improvement projects, MidAmerican assigns a value to customer outage costs, which reflects the value that customers assign to avoid an outage. Customer outage costs include *unserved-energy costs*, which are determined by multiplying the unserved kilowatthours by a $/kWh factor established by MidAmerican for its customers, and *momentary-outage costs*, which are deter-

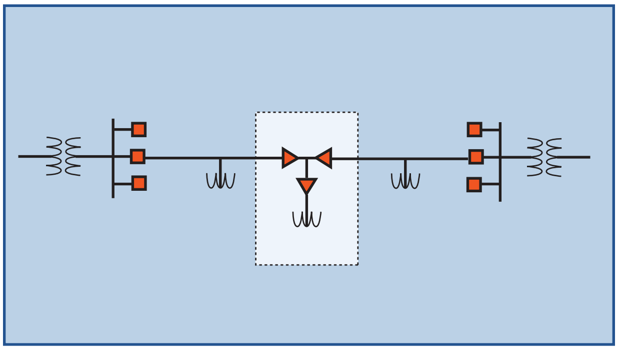

figure 3. Single-transformer substation.

A benefit-cost analysis determines which of the candidate SA functions identified during the information-exchange process is economically justified.

mined by multiplying the power interrupted in kilowatts by a predetermined $/kW factor.

Customer outage cost savings, which are typically much higher than the direct monetary savings to MidAmerican, were not included in the analysis of revenue requirements, which included the direct monetary savings only. Instead, customer outage costs were analyzed separately for comparison with other reliability improvement initiatives contemplated by MidAmerican.

Analysis of Revenue Requirements

The annual SA system benefits were compared to the annual SA system costs for each year over the life of the investment. The investment life was assumed to be ten years. Two commonly used financial indicators were computed to measure the economic viability and merit of the investment.

- ✔ *Benefit-cost ratio (BCR)* is the ratio of cumulative benefits during the first ten years of SA system operation to the cumulative costs to operate and maintain the system during the first ten years of operation.
- ✔ *Payback year* is the first year during the life of the system when the cumulative benefits exceed the cumulative costs by the initial purchase cost.

To determine which SA system candidate functions (if any) should be implemented, the analysis of revenue requirements was repeated for various combinations (scenarios) of candidate functions. This analysis of scenarios enabled MidAmerican to determine which combination of SA functions was economically most attractive. Since the analysis was performed using spreadsheets, it was possible to analyze all possible combinations of candidate functions.

By removing the candidate functions one at a time from the complete set of functions, MidAmerican was able to identify the individual functions that offered the highest payback. For example, if the overall benefit-cost ratio goes way down (becomes less attractive financially) when a function is removed, that individual function is economically attractive. On the other hand, if the overall benefit-cost ratio does not change significantly or actually improves when a function is removed, that function is not economically attractive and should not be implemented.

Sensitivity Analysis

The results of the revenue requirements analysis depend on many assumptions about key economic and technical parameters, many of which are not controllable by MidAmerican. Minor changes in some key variables could produce a significant change in the results that could impact the recommendations. To determine which input parameters have the most significant impact on the results of the analysis, a sensitivity analysis was performed. All input parameters were varied (one at a time) by ±20% of its base value to determine the impact on the final results. Those variables that produced the most impact on the benefit-cost ratio are key variables that were carefully examined to ensure accuracy.

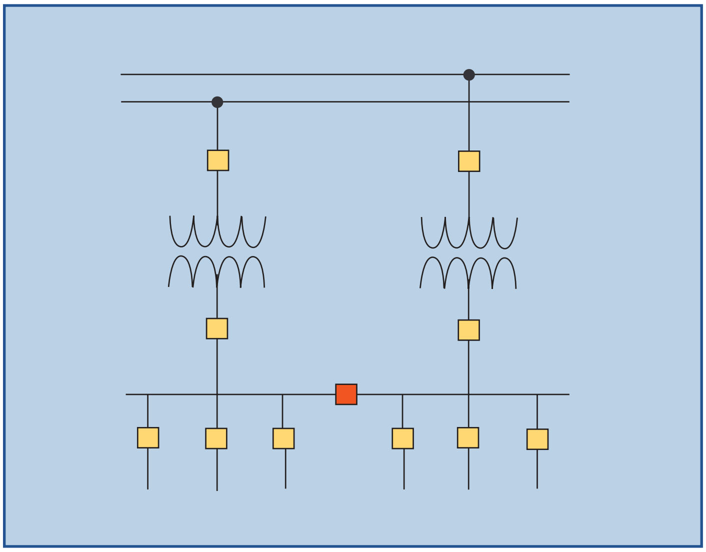

figure 4. Two-transformer substation.

Presentation of Results

The ongoing success of the project depends heavily on management acceptance of the findings, conclusions, and recommendations of the study. Therefore, in addition to preparing a clearly written report to document the study, several meetings were held with key management officials to inform them of project plans, projected costs, and expected benefits. This ensured that all of their questions were answered to their satisfaction, ensuring their continuing support during the actual implementation.

Business Case Results

Candidate Functions

Candidate SA functions identified for MidAmerican are:

- online equipment condition monitoring
- dynamic transformer ratings
- adaptive relay settings
- power system disturbance analysis
- automatic load restoration.

A brief description of each follows.

Online Equipment Condition Monitoring

Many electric utilities have employed online equipment condition monitoring (ECM) to maintain electric equipment in top operating condition while minimizing the number of interruptions and reducing the frequency of routine inspections. With ECM, equipment operating parameters are tracked automatically to detect the emergence of various abnormal operating conditions. This allows operations personnel to take timely action when needed to improve reliability and extend equipment life. For MidAmerican, ECM for high-voltage, supply-line circuit breakers and ECM for substation transformers were identified as candidate SA functions.

The projected benefits of ECM for high-voltage supply-line circuit breakers and substation transformers include:

- *Fewer routine inspections:* By implementing an effective online monitoring system for this equipment, fewer routine maintenance inspections will be needed. For MidAmerican, it was assumed that the major maintenance inspection interval for high-voltage supply-line circuit breakers (based on number of fault operations, results of testing dielectric medium, and time since last maintenance period) could be increased from three years to six years. It was also assumed that the maintenance inspection interval for substation transformers (based on testing dielectric medium, load tap changer operations, and time since last maintenance period) could be increased from two years to five years. The benefit of fewer inspections attributable to this candidate SA function is a reduction in labor and material costs associated with these inspections.
- *Fewer catastrophic failures:* By implementing continuous online monitoring, some equipment problems can be detected early, so that corrective action can be taken before a catastrophic failure occurs. For MidAmerican, it was assumed that 15% of high-voltage supply-line circuit breaker problems and 20% of substation transformer problems could be detected before catastrophic failure occurs. In most cases, the cost to repair equipment problems will be significantly less if the problem is addressed before a catastrophic failure occurs. For MidAmerican, it was assumed that the repair costs could be reduced by 10% for circuit breakers and by 67% for substation transformers. Furthermore, equipment outages to perform such repairs can be planned so that customer outages can be minimized, resulting in a reliability improvement benefit that can be attributed to this SA system candidate function.
- *Equipment life extension:* The average life of a piece of equipment can be extended if the equipment shows no significant signs of wear. Therefore, it was assumed that the life expectancy of a high-voltage supply-line circuit breaker or substation transformer can be extended by employing better monitoring to identify such signs of wear. By increasing the life expectancy of the monitored equipment, it will be possible to defer capital expenditures to replace this equipment. For MidAmerican, it was assumed that the average life expectancy of its high-voltage supply-line circuit breakers and substation transformers could be extended by one year by employing continuous equipment monitoring. Therefore, the monetary savings associated with deferred capital expenditures can be attributed to this SA system candidate function.

Dynamic Equipment Ratings

Newer transformers being procured by MidAmerican all have short-term overload capabilities. Older transformers have the capability of being overloaded as long as internal temperature limits are not being exceeded. Even though transformers have some inherent overload capacity, system operators are reluctant to load transformers beyond their nameplate limits due to lack of specific information on current conditions.

Detailed equipment measures provided by the ECM devices, such as transformer winding temperatures, would allow MidAmerican to determine equipment ratings based on actual conditions rather than on conservative assumptions about operating and ambient conditions. Under some circumstances, this will enable MidAmerican to gain additional capacity from existing equipment during peak load periods. This, in turn, will allow MidAmerican to defer capital expenditures and, in some extreme cases, can help avoid load shedding to avoid equipment overloads.

Adaptive Relay Settings

The SA system will enable MidAmerican to change protective relay settings from one group of predetermined settings to another group of predetermined settings from a remote location. This application function will enable MidAmerican to change normal feeder protective-relay settings to fuse-saving settings under conditions (such as storms) when numerous momentary faults are likely to occur. Fuse saving will prevent feeder branch line fuses from blowing for momentary faults, thus avoiding unnecessary extended outages for some customers at the expense of numerous momentary outages for all customers on the feeder. Significant improvement in reliability indicators (SAIDI and SAIFI) can be achieved at MidAmerican by employing remote controlled fuse saving. Analysis performed on one of MidAmerican's feeders showed that the average outage duration could be reduced by at least 20% by implementing fuse-saving settings during stormy (or

> Ongoing project success depends heavily on management acceptance of the study's findings, conclusions, and recommendations.

windy) weather conditions. Therefore, significant reliability improvement benefits can be attributed to this SA system candidate function.

The capability to switch protective relay settings remotely to alternate predetermined settings will reduce the number of field trips made by relay technicians to make these changes locally. Such protective-relay setting changes are often required when feeder circuits are reconfigured. The result is a small savings in labor costs that can be attributable to this SA system candidate function.

Power System Disturbance Data

Protective-relay IEDs contain a wealth of data that can be useful in analyzing power system disturbances. Protective-relay IED information, such as relay targets, fault current magnitude, and fault location information, can assist system operators, substation operators, field crews, and others in determining the cause and location of the faulted equipment to speed switching to restore service to customers. Oscillographic (waveform) data and sequence-of-event data available in the protective-relay IEDs provide valuable information that can be used by relay engineers and relay technicians to diagnose possible relay misoperations. This after-the-fact analysis is used to zero in on the problems, identify any misoperations, and ensure proper operation of these devices for future problems.

Currently, MidAmerican personnel can access much of this protective-relay information via dial-up connections. However, the SA system will provide MidAmerican with a more convenient and secure mechanism to access the IED data. Having more convenient access to the power system disturbance data contained in IEDs (relay targets, fault location and magnitude, etc.) will assist field crews in investigating and locating the fault and thereby reduce both investigation time and feeder patrol time. This reduces the average customer outage duration, which in turn results in a significant reliability improvement benefit. Reduced fault investigation and feeder patrol times also produce a small labor savings that can be attributed to this SA system candidate function.

Automatic Load Restoration

This SA system candidate function will enable MidAmerican to automatically restore power to customers whose service has been interrupted due to a high-voltage supply-line or substation transformer failure.

Some of MidAmerican's smaller single-transformer substations do not have high-side circuit breakers that can be used to sectionalize a faulted supply line. Figure 3 depicts this type of substation. As a result, when a supply-line fault occurs, customers served by these substations would be without power until field crews repair the faulted line or manually sectionalize the supply line to isolate the faulted segment of the supply line. The SA system, using fault-location information received from protective relays at opposite ends of the supply line, can determine the approximate location of the fault, open appropriate motor-operated disconnects, and signal system operators to close the appropriate supply line, thus speeding the restoration of power to the substation. Fully automated operation is possible, but MidAmerican has elected to use the semiautomated version of this application at this time due to the complexity of the automated solution. A significant reliability improvement benefit can be attributed to this SA system candidate function. A small monetary benefit for reduced manual switching activities (labor savings) and reduction of lost revenue from kilowatthour sales can also be attributed to the SA system.

The automatic load-restoration function will also provide additional benefits at two-transformer substations. A typical two-transformer substation is depicted in Figure 4. Simple automatic transfer schemes that are designed to transfer feeder load following a supply line or substation transformer have been disabled in some substations due to concerns that additional load will overload the remaining healthy transformer. The automatic load-restoration function will be able to determine how much load can be transferred safely to the backup transformer and then issue appropriate switching commands

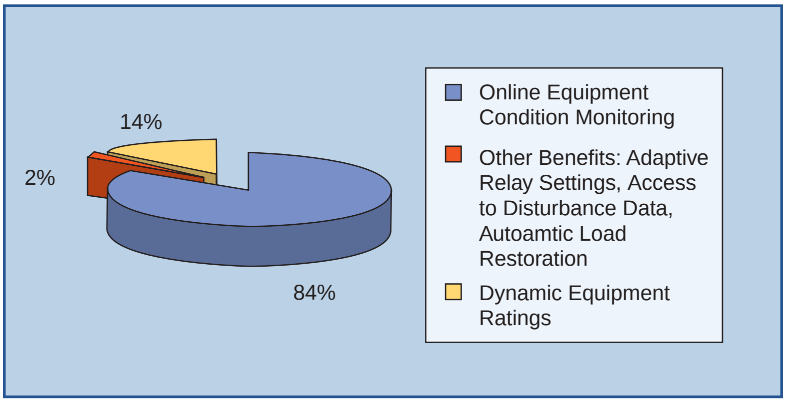

figure 5. Direct monetary benefits.

table 2. Scenarios analyzed for monetary benefits and results.

Overall Rank	ECM for HV Breakers	ECM for LTC Transformers	Adaptive Relay Settings	Disturbance Data	Automatic Load Restoration	Dynamic Equipment Rating	BCR	Payback
1	0	1	1	1	1	1	1.597	8
2	0	1	0	0	0	0	1.408	12
3	1	1	1	1	1	1	1.354	16
4	1	1	1	1	0	1	1.346	16
5	1	1	1	0	1	1	1.341	17
6	1	1	1	1	1	1	1.337	17
7	1	1	0	1	1	1	1.334	17
8	1	1	0	0	0	0	1.183	99
9	1	1	1	1	1	0	1.162	99
10	0	0	0	0	0	1	0.954	99
11	0	0	1	1	1	1	0.894	99
12	1	0	1	1	1	1	0.670	99
13	1	0	0	0	0	0	0.289	99
14	0	0	1	0	0	0	0.200	99
15	0	0	0	0	1	0	0.172	99
16	0	0	0	1	0	0	0.170	99

to transfer the maximum possible load. The benefit that is attributable to the SA system would be the reduction of outage duration, lost revenue, and customer outage costs.

Summary of Benefits

Direct Monetary Benefits

The relative percentages of the direct monetary benefits for each candidate SA function are illustrated in Figure 5.

Customer Outage Benefits

The relative percentages of the customer outage benefits for each candidate SA function are illustrated in Figure 6.

SA System Costs

The SA system costs used in the benefit-cost analysis include basic SA system hardware and software plus additional costs to implement the candidate SA functions on the basic SA system platform, including specialized sensors and application software. Procurement and installation costs were included in the analysis, and costs to maintain the equipment over the life of the SA system were also factored in. The relative cost percentages for each item are shown in Figure 7.

Benefit-Cost Analysis

Analysis of Monetary Benefits

The analysis was repeated with various combinations of the SA functions under consideration being implemented or not

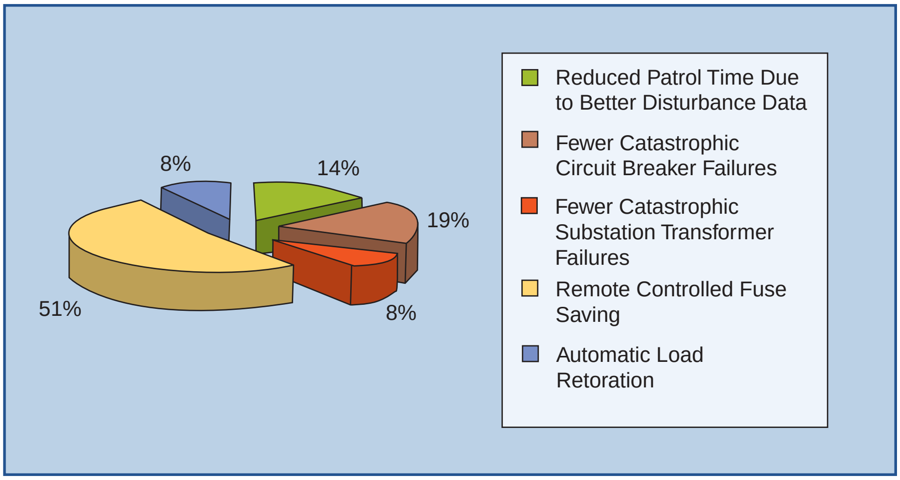

figure 6. Customer outage benefits.

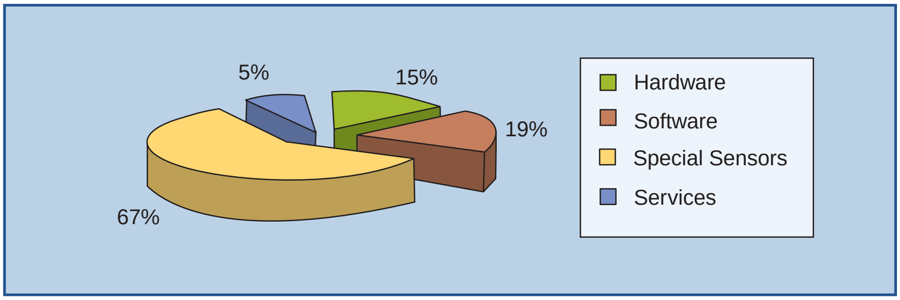

figure 7. Relative cost percentages.

implemented to determine the combination of SA system functions yielding the highest returns. Only the hard monetary benefits were included in this analysis. Table 2 identifies the scenarios that were analyzed along with the results (BCR and payback period) for each scenario. The table entries have been ranked by hard dollar benefit-cost ratio, with scenarios offering the highest payback appearing at the top of the list. Note that a "1" indicates that the function was included in the scenario; "0" indicates that the function was excluded from the scenario.

Analysis of Customer Outage Benefits

The analysis of revenue requirements was repeated for the same scenarios using only the customer outage cost benefits. Table 3 identifies the scenarios that were analyzed along with the results (BCR and payback period) for each scenario. The table entries have been ranked by customer outage benefit-cost ratio, with scenarios offering the highest payback ranked the highest.

Combined Ranking

To account for both monetary benefits and reliability-

table 3. Scenarios analyzed for customer outage benefits and results.

Rank	ECM for HV Breakers	ECM for LTC Transformers	Adaptive Relay Settings	Disturbance Data	Automatic Load Restoration	Dynamic Equipment Rating	Customer Outage BCR	Customer Outage Payback
1	0	0	1	1	1	1	8	1
2	0	0	1	0	0	0	6	1
3	1	0	1	1	1	1	5	2
4	0	1	1	1	1	1	3	4
5	1	1	1	1	1	1	3	4
6	1	1	1	1	1	0	3	4
7	1	1	1	1	1	1	3	4
8	1	1	1	1	0	1	3	4
9	1	1	1	0	1	1	2	5
10	0	0	0	1	0	0	2	8
11	1	1	0	1	1	1	1	11
12	1	0	0	0	0	0	1	15
13	0	0	0	0	1	0	1	99
14	1	1	0	0	0	0	1	99
15	0	1	0	0	0	0	0	99
16	0	0	0	0	0	1	0	99
17	0	0	0	0	0	0	0	99

table 4. Combined ranking of monetary and reliability-improvement benefits.

ECM for HV Breakers	ECM for LTC Transformers	Adaptive Relay Settings	Disturbance Data	Automatic Load Restoration	Feeder Automation Support	Dynamic Equipment Rating	Monetary Benefits Rank	Customer Outage Rank	Total Rank
0	1	1	1	1	1	1	1	4	5
1	1	1	1	1	0	1	3	4	7
1	1	1	1	0	1	1	4	4	8
1	1	1	1	1	1	1	6	4	10
0	0	1	1	1	1	1	11	1	12
1	1	1	1	1	1	0	9	4	13
1	1	1	0	1	1	1	5	9	14
1	0	1	1	1	1	1	12	3	15
0	0	1	0	0	0	0	14	2	16
0	1	0	0	0	0	0	2	15	17
1	1	0	1	1	1	1	7	11	18
1	1	0	0	0	0	0	8	11	19
1	0	0	0	0	0	0	13	11	24
0	0	0	1	0	0	0	16	9	25
0	0	0	0	0	0	1	10	15	25
0	0	0	0	1	0	0	15	11	26
0	0	0	0	0	1	0	17	15	32

% Change in BCR

Data Item	–20	20%	Bandwidth
Carrying Change-Electronic and Comm. Equip.	–21.4	15.0	36.39
Alternative 3 Cost Multiplier	–17.7	13.1	30.75
Number of Feeders per Set of Dist. Sub. Regulators	13.8	–13.8	27.53
Load Factor	11.5	–12.9	24.41
Distribution PFat at Pk	–10.1	9.9	19.98
Wholesale Energy Cost	8.4	–8.4	16.77

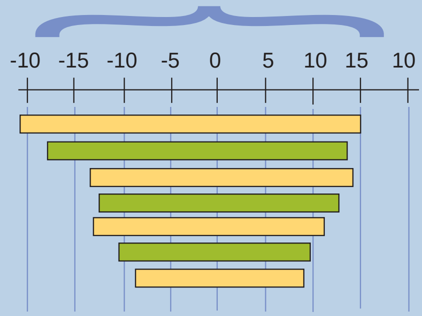

figure 8. Sensitivity analysis results.

improvement benefits, a total rank was calculated for each scenario by adding the monetary rank and the customer outage rank. The results are shown in Table 4.

Sensitivity Analysis

The results of the revenue requirements analysis depends on many assumptions about key economic and technical parameters, many of which are not controllable by MidAmerican. Minor changes in some key variables could produce a significant change in the results that could impact the recommendations. A sensitivity analysis has been performed to determine which input parameters have the most significant impact on the results of the analysis (Figure 8). Each input parameter was varied by ±20% of its base value to determine the impact on the final results.

Project Status

MidAmerican is proceeding with an SA validation project based on the results of the business case and currently plans to install SA systems at two substations. MidAmerican has elected to implement an SA system at a large two-transformer distribution substation that has only a limited amount of IED integration but a fair payback in terms of MidAmerican and customer outage benefits. MidAmerican has also selected a newer one-transformer substation with a high degree of IED integration that is a good model for future substation construction projects. MidAmerican plans to install SA systems at these pilot locations and then review the actual benefits before proceeding with further projects.

Biographies

Steve Haacke, manager of Substation Engineering for MidAmerican Energy, has over 23 years of experience in the electric utility industry. He has held various engineering positions with MidAmerican Energy, primarily in the distribution, transmission, and substation design departments. He has a B.S. degree in electrical engineering from the University of Nebraska.

Sam Border, a senior engineer at MidAmerican Energy Company, has over 29 years of experience as an electrical engineer. He is currently a project manager in the company's Substation Engineering department and is actively working on MidAmerican Energy's substation automation validation project. He was formerly supervisor of the EMS operations group and was project manager for an EMS installed in 1990. He has a B.S. degree in electrical engineering from the University of Illinois at Urbana. He is a registered professional engineer in Iowa and a member of the IEEE Power Engineering Society.

Dehn Stevens is a supervisor in the Electric System Planning department at MidAmerican Energy Company. His responsibilities at MidAmerican include supervisory responsibility for electric transmission and distribution system planning for several regions of MidAmerican's system as well as administering generation interconnections to the MidAmerican electric system. He served on the substation automation investigation team. He has a B.S. degree in electrical engineering from Iowa State University. He is a registered professional engineer in Iowa and Illinois.

Bob Uluski, senior principal consultant at KEMA Consulting, has over 29 years of experience in the electric utility industry. He has assisted numerous North American and international electric utilities with the procurement and implementation of distribution automation systems. He specializes in developing the business case for implementing substation and feeder automation and has developed computer programs to assist in performing the detailed benefit-cost analysis for such projects. He has an M.S. degree in power system engineering from the University of Wisconsin at Madison. p&e