Proceedings of the Fifth IASTED International Conference
POWER AND ENERGY SYSTEMS
June 15-17, 2005, Benalmádena, Spain

DESIGNING URBAN DISTRIBUTION SYSTEMS USING VALUE-BASED PROBABILISTIC MODELS

A. A. Chowdhury
Electric System Planning
MidAmerican Energy Company
Davenport, Iowa 52801
USA

D. O. Koval
Department of Electrical and Computer Engineering
University of Alberta
Edmonton, Alberta
Canada T6G 1G4

ABSTRACT: Achieving high distribution reliability levels and concurrently minimizing capital costs can be viewed as a problem of optimization. Assuming given outage rates and repair times, distribution system design is the remaining factor in determining customer reliability. Including customer value of reliability in an economic analysis allows for optimization of the major components of distribution system design. Using mathematical models and simulations, a comparison of design concepts can be performed to compute the optimal feeder section length, feeder loading level, and distribution substation transformer loading level. The number of feeder ties and feeder tie placement are also optimized through the models. The overall outcome of this analysis is that capital costs can then be directed towards system improvements that will be most cost-effective in improving system reliability. This paper presents a value-based probabilistic approach to designing urban distribution systems. The value-based reliability methodology is illustrated using a practical urban distribution system of MidAmerican Energy Company.

Key Words – Urban, distribution system, value-based, reliability, feeder ties, tie placement, optimal design

I. INTRODUCTION

THE importance of electricity supply reliability that influence customer's purchasing decision is being recognized by electric utilities as the electricity industry is moving towards deregulation and customer choice. The distribution system is an important part of the total electric supply system as it provides the final link between a utility's bulk transmission system and its ultimate customers. It has been reported in many technical publications that over eighty per cent of all customer interruptions occur due to failures in the distribution systems.

In the past, the distribution segment of a power system received less of the attention dedicated to reliability planning than have generation and transmission segments, and therefore the distribution segment has been the weakest link between the source of supply and the customer point of utilization. This is due to the fact that generation and transmission segments are very capital intensive and outages in these segments can have widespread catastrophic economic consequences to both utilities and customers. Though a distribution system reinforcement scheme is relatively inexpensive compared to a generation or a transmission improvement plan, a utility routinely spends a large sum of money collectively on a number of distribution improvement projects.

Including customer value of service reliability in an economic analysis permits the optimization of the major components of distribution system design. Using mathematical models and simulations, a comparison of different design concepts can be performed to compute the optimal feeder section length, the feeder loading level, and the distribution substation transformer loading level. The number of feeder ties and feeder tie placement can also be also optimized through the probabilistic models. The overall outcome of this analysis is that capital costs can then be directed towards system improvements that will be most cost-effective in improving distribution system reliability. This paper presents a value-based probabilistic approach to designing urban distribution systems. The value-based probabilistic method is illustrated using a practical urban distribution system of MidAmerican Energy Company. The primary computing tool used for distribution reliability assessment is DISREL program. The program is described in [1].

II. VALUE-BASED RELIABILITY ASSESSMENT IN A DEREGULATED ENVIRONMENT

At present, deregulation of the electric energy industry is forcing electric utilities into uncharted waters. For the first time, the customers are having opportunities to look for value-added services from their suppliers or they will start to shop around. It is a foregone conclusion that failure to recognize customer preferences in a competitive market would bring disastrous results to many utilities. The emerging competitive energy market will be characterized by intense price competition. Utilities will be faced with new challenges of budget constraints, safety, environment, lower load growth, need for more involvement of different interest groups in the planning and design process, and more competitive independent distributed generators. More over, electric utilities will be under conflicting pressures of providing even higher standards of service reliability and hold the line on rates.

It is apparent that modern society is increasingly becoming dependent on cost- effective reliable electric power supply, and unreliable electric power supplies can be extremely costly to both utilities and customers. It has also been recognized that rules of thumb and implicit criteria cannot be used in a consistent manner when a very large number of capital and O&M investments are routinely being made. There is therefore a growing interest in economic optimization approaches to distribution system planning and expansion. In order to render a rational means of decision making on the requirements of changing the supply reliability levels experienced by customers; utility costs and the costs incurred by customers associated with interruption of service must be incorporated in the distribution system planning practices.

A value-based distribution system reliability planning approach attempts to locate the minimum cost solution where the total cost includes the utility investment costs plus the operating costs plus the customer interruption costs. Value-based distribution system reliability planning, therefore, becomes an invaluable tool utilizing which a pro-active, customer-responsive utility will be able to retain its existing customer-base and win new customers [2-8]. This paper illustrates the utilization of a value-based reliability method in the optimal design of urban distribution systems that benefits both electricity suppliers and customers. The value-based planning approach is illustrated using a practical urban distribution system.

III. The Characteristics Of The Illustrative Urban Distribution System

Though normally operated radially, urban areas with high density commercial, industrial, residential, government and institutional loads are supplied from a number of meshed distribution supply systems such as primary selective systems, primary loop systems, and secondary grid networks. On the other hand, the sparsely populated rural service areas with a mix of commercial and residential customers are normally serviced by overhead radial distribution systems.

Although variations exist among urban feeders across the MidAmerican service territory, the majority of the urban feeders have principally similar characteristics. In order to broadly apply conclusions reached in the study, the features of a typical urban distribution feeder and substation were agreed upon and used in the study. These typical features of the MidAmerican urban distribution system are: 1) the load density is 2.5 MW per mainline feeder mile, 2) the feeder normal rating is 10 MVA and the emergency rating is 11.6 MVA, 3) the feeder length and conductors used on the urban system prevent voltage from limiting backup capability, and 4) the typical urban distribution substation consists of dual 33 MVA transformers each with an emergency rating of 48 MVA.

Based on these criteria, an existing MidAmerican urban circuit was selected for use in the study. The selected circuit serves a peak load of 8.2 MW, and consists of 2.9 miles of three-phase mainline, 2.3 miles of fused three-phase taps, and 7.4 miles of fused single-phase taps. The circuit is shown in Fig. 1.

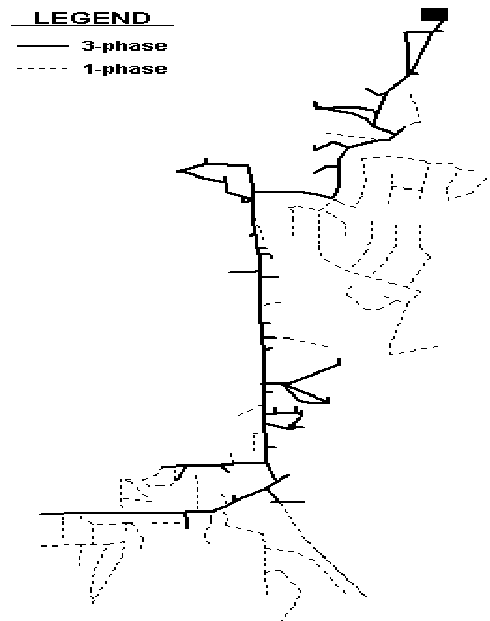


Fig. 1. Illustrative urban distribution system

The greatest impact on customer reliability from a design standpoint can be obtained from improving mainline reliability. So for study purposes, the circuit was reduced to the three-phase mainline. Loads and customers on fused taps were lumped back to the mainline section serving the tap.

The study was performed using equipment failure rates and repair times, which were based upon past performance on the MidAmerican urban distribution system and industry averages. A listing of the failure rates and repair times used in the study is shown in Table I.

TABLE I
COMPONENT FAILURE RATES & REPAIR TIMES

Component	Failure Rate (F)	Repair Time (RT)
Substation Transformer	0.07/year	24 hours
Bus/Switchgear	0.001/yr	15 hours
Circuit Breaker	0.0036/yr	32 hours

3-phase UG	0.35/mi-yr	18 hours
3-phase OH	0.8/mi-yr	4 hours
Switch	0.001/yr	5.5 hours

The assumed switching time used in the study was 60 minutes to isolate a failure, plus an additional 10 minutes to close feeder ties where available. The average customer interruption cost figure used in the cost-benefit analyses is $10.76/kWh. The approach used in this paper was to take an existing SynerGEE (Advantica Stoner's primary distribution analysis software) feeder model and make modifications to represent different types of distribution circuit layout. DISREL was then used to simulate the models and determine the expected unserved energy for each scenario. The unserved energy in kWh can be converted to a cost based upon customer value of reliability. In this manner, system modification costs can be compared against the associated reliability benefits to determine if the improvements are economically justifiable. Including reliability benefits, various system layouts were compared using economic analysis in order to arrive at the optimal layout for a distribution system. A number of urban distribution system design criteria were optimized and are described in the following sections. A brief description of the items optimized and the process used is described in the following.

Optimal feeder mainline section length was calculated mathematically by deriving an equation for the reduction of unserved energy costs associated with adding a switch at the midpoint in a single mainline section. The optimal section length was then calculated by setting reduction in unserved energy costs equal to the cost of the switch installation. Equations are included in Appendix A.

Optimal number of feeders and transformer loading were determined by performing simulations to calculate the unserved energy costs for the total load served by an urban distribution substation. Simulations were run at different system load levels (100%, 80% 70%, etc) and annual unserved energy cost was calculated by weighting the results of each simulation by the percent of the year that each load level is present. The five-step load model used in the study is presented in Table II.

TABLE II
FIVE –STEP LOAD DURATION CURVE APPROXIMATION

LOAD LEVEL	PROBABILITY
100% (PEAK)	0.001
80%-90%	0.025
70%-80%	0.040
60%-70%	0.097
<60%	0.837

The annual unserved energy cost for a particular transformer and feeder loading scenario was then added to a charge for any unused transformer and feeder capacity to create the total annual cost of the loading scenario. Annual costs of each loading scenario were then compared to determine the most cost effective solution. Equations are included in Appendix B.

The optimal number of feeder ties was determined by performing simulations to calculate the unserved energy for a single feeder while varying the number of feeder ties. The incremental reduction in unserved energy costs associated with each feeder tie addition is then compared against the incremental cost of installing the tie. Differing levels benefit are obtained when adding feeder ties depending on where the tie is located.

IV. DISCUSSION OF RESULTS

A. Feeder Section Length

The optimal section length can be mathematically determined independently of the other distribution system design issues if two assumptions are made. The first assumption is that once a faulted section is isolated, there is enough feeder tie capacity to serve the remaining sections. This is a safe assumption taking into account the MidAmerican load duration curve (See Table II). Over 93% of the hours fall at 60% load level or less. At 60% loading, even one tie should be able to cover the circuit assuming that voltage is not a limiting issue. Also, for most faults, the feeder ties will not be required to pick up the entire feeder because a portion of the feeder will be served by the normal source, unless one of the first sections is faulted.

The second assumption is that load along the feeder is uniformly distributed. This may not be the case, but the majority of the benefit of adding sectionalizing switches comes from shortening section length, no matter what the load distribution. If there is large spot load, additional switches can be put on either side or both sides to protect it.

Once these two assumptions are made, a mathematical analysis can be made for the addition of switches. The benefit in unserved energy cost reduction can be calculated, and since the cost of the switch and installation is also known, the analysis can be used to determine optimal section length with a cost-benefit analysis. A detailed derivation of the equations can be found in Appendix A. Table III shows the results of the cost-benefit analysis taking into account customer reliability benefits and using different years-to-payback. It should be noted that the calculation used equipment and installation costs of overhead distribution switches, and therefore the resulting section length is applicable to overhead portions of the three-phase feeder.

TABLE III
OPTIMUM SECTION LENGTHS

Years to Payback	Length (mi)	Length (ft)
1	0.26	1396
2	0.19	1012
3	0.16	846
4	0.14	751
5	0.13	687

The results in Table III indicate a rather short section length is beneficial even using a one-year payback period. Using the results from this analysis, it was decided to modify the feeder to have a section length of around 1000 feet. The circuit originally had 5 sectionalizing switches over a length of about 2.9 miles; therefore 11 more switches were added in order to bring the section length to around 1000 feet.

B. Feeder and Transformer Loading Levels

Feeder and transformer loading also need to be addressed to set up the base case. To perform this part of the analysis, the circuit was modified to reflect different feeder load levels. Additional sections were added in specific cases to represent the circuit configuration for a higher loaded feeder. Using DISREL unserved energy costs associated with different feeder loading levels was determined.

The unserved energy costs decrease as feeder load levels are lowered; however, to allow for a comparison of alternatives, a charge was applied for unused feeder and transformer capacity. In order to fairly incorporate the transformer loading, the approach used was to determine the unserved energy cost and unused capacity charge associated with serving 33 MVA of load. That way, each alternative case could be directly compared against a base case that was selected to be a completely loaded transformer with three 11 MVA feeders. Cost-benefit analysis was performed on each of the cases, where the benefit was the difference between the unserved energy costs of the base case and the unserved energy costs of the alternative case. The cost for the alternative case was the capacity charge associated with operating the system below full nameplate capacity levels. The values used for capacity charges were those agreed upon for alternate source calculations and are listed in Appendix B.

Each alternative case was run using 2 feeder ties and a bus tie, because earlier runs indicated that was the optimal way to operate the system no matter what load level was chosen. Table IV shows the calculated results.

TABLE IV
Feeder & Transformer Loading Comparison

MVA	Feeders per Xfmr	Unserved Energy (kWh)	UE for 33MVA (kWh)	Unused Capacity Cost	Xfmr Load Losses	Benefit (Annual)	Years to Payback
11	3	$226,468	$679,403	$0	$25,826	$0	-
10	3	$190,744	$629,455	$88,896	$22,155	$53,620	**3**
9	3	$158,484	$581,110	$205,230	$18,833	$105,287	**3**
8	4	$129,799	$535,423	$102,800	$24,563	$145,243	**1**
7	4	$105,460	$497,168	$257,912	$19,901	$188,160	**2**
6	4	$84,420	$464,310	$413,024	$15,860	$225,058	**3**

Utility Cost Benefit Analysis Model (UCBM) was used to calculate the years to payback for each alternative [9]. The option with the shortest payback period indicates that it is the most economical way to serve the load taking into account customer value of reliability. Since the transformer capacity charge is much larger than the feeder capacity costs, the results show that loading the transformer closer to nameplate rating is advantageous. Also, because most of the unserved energy costs come from faults on the line, increasing the transformer loading only incrementally increases unserved energy costs.

C. Bus and Feeder Tie Analysis

Once the base case was determined, it was used to verify how many feeder ties are cost beneficial taking into account customer value of reliability. Using the results from Tables III and IV, the base case was chosen as an 8 MVA circuit with a section length of approximately 1000 feet. Starting at a base case with no ties, ties were added one at a time and UCBM was used to determine if that incremental change was beneficial. The calculated results for each addition are shown in the Table V.

TABLE V
Cost-Benefit Analysis of Adding Bus Tie

Tie	Incremental Cost	Incremental Benefit (Annual)	Years to Payback
Bus Tie	$100,000	$79,789	2
Feeder Tie #1	$0	$152,367	<<1
Feeder Tie #2	$13,384	$302	>30
Feeder Tie #3	$6404	$3	>30

<u>Tie Costs & Descriptions</u>

The bus tie was simulated in the analyses as a backup source to the distribution substation switchgear in the case of a transformer failure. The cost of bus tie was estimated at $100,000 and consisted of two breakers and associated cable work for the bus tie installation. The first feeder tie was simulated as a backup source at the end of the feeder, because typically as the distribution system expands outward a normally closed switch turns into a normally open tie point. Therefore, the cost of this improvement was set to $0. The second and third feeder ties were simulated as backup sources near the midpoint and quarter-point of the feeder respectively. The cost of these improvements consisted of the switch and three-phase construction required to connect the test feeder to an assumed adjacent feeder. Appendix C illustrates how the three-phase construction cost was calculated. Since the test feeder and the adjacent feeder each receive a benefit from a feeder tie, the three-phase construction cost was cut in half for the cost-benefit analysis.

The results shown in Table V indicate large benefits associated with adding the bus tie and adding the first feeder tie. However, the benefit gained from adding the second and third feeder ties is very small.

D. Maintenance

The simulation results indicate that in many cases only one tie is cost beneficial. While having only one tie may be economically advantageous, switching options are greatly reduced, especially when one circuit is restricted due to maintenance or construction projects such as road widening. If a fault occurred when the tie was unavailable, it would lead to significant customer outage duration. In order to include this aspect, two different scenarios, one with the second tie, and one without the second tie, can be combined to represent a system with feeder tie availability considered. The only requirement is to determine what percentage of a year the tie typically is unavailable. Appendix D illustrates the computation model. Table VI summarizes the results with maintenance included.

TABLE VI
COST-BENEFIT ANALYSIS OF 2ND TIE INCLUDING MAINTENANCE CONSIDERATIONS

Frequency of Maintenance	Benefit of 2nd Tie	Cost	Years to Payback
4 weeks every 1 year	$11,990	$13,384	2
4 weeks every 3 years	$4,198	$13,384	6
4 weeks every 5 years	$2,639	$13,384	12
4 weeks every 10 years	$1,470	$13,384	>30

Table VI illustrates that when maintenance is included, the benefit of the second tie is more apparent. As the maintenance becomes less frequent, meaning the tie is available for a higher percentage of the year, the benefit of adding the second tie decreases considerably.

E. Single Transformer

Cases were also run to see if the results differ for a single transformer substation. In these cases, the bus tie was removed, and all ties were assumed to be from circuits served from the same transformer, excluding the tie at the end, which was assumed to be from a circuit served from another substation. Because the bus tie is only used for transformer faults, which is a small percentage of all faults, these results tend towards the same conclusions as a two-transformer substation. Even without the bus tie, the feeder tie at the end of the circuit will be able to pick up a large portion of an 8 MVA feeder during many hours of the year, considering MidAmerican's load duration curve. In order for the feeder ties to pick up significant load for a transformer failure, there needs to be an emergency rating on the transformers at the surrounding substations.

F. Conductor Sizing

In most areas, the distribution system can be classified as a 600 Amp system, and in most instances, conductor sizes can be chosen in accordance with that concept. However, in areas where voltage limitations are a concern, larger conductor has been used to help return the system to ampacity-limited rather than voltage-limited. Designing the system using a larger conductor can be the economical solution for systems where voltage limitations exist. However, in an ampacity-limited system, selecting a larger conductor size will not provide significant benefit in terms of reliability. To illustrate this point, additional scenarios were run to compare the benefit in reliability from having increased available tie capacity. The results of the simulation show that installing a larger sized conductor strictly for increasing tie capacity is not cost justified when taking into account customer value of improved reliability.

G. Feeders With Non-fused (Lateral) Three-phase Branches

Another issue to address is adding ties for three-phase non-fused (see Fig. I) lateral branches on a circuit. For long branches off the main circuit, considerable unserved energy costs can be observed if there is no backup tie. An equation representing the benefit of adding a tie for branches of different lengths is presented in Appendix E. Table VII summarizes the reduction of unserved energy costs for various branch lengths.

It is apparent that as the length/load of the three-phase branch increases the benefit of constructing an additional feeder tie at the end of the branch also increases. Assuming that a project with a five-year payback period is economically justifiable, the last column in the table indicates the allowable costs associated with constructing the additional feeder tie for a generic feeder.

TABLE VII
BENEFIT OF ADDITIONAL TIE FOR THREE-PHASE BRANCHES

Branch Length (miles)	ΔUE Sections (MWh)	ΔUE Switches (MWh)	ΔUE Total (MWh)	Benefit	Feeder Tie Investment Allowed for 5 y payback
0.2	0.0	0.0	0.0	$0	$0
0.4	226.7	2.2	228.8	$2,462	$7,205
0.6	680.0	4.3	684.3	$7,363	$21,549
0.8	1360.0	6.5	1366.5	$14,704	$43,034
1.0	2266.7	8.7	2275.3	$24,483	$71,654
1.0	3400.0	10.8	3410.8	$36,701	$107,412
1.4	4760.0	13.0	4773.0	$51,357	$150,306

H. Feeder Tie Placement

Feeder tie points should be spread evenly across the circuit taking into account customer loading. Considering a feeder tie as an additional source verifies this conclusion. Spreading out the sources allows more customers to be picked up following an outage. An example of this on a system with only one feeder tie is shown in Fig. 2. A failure occurring at the spot marked "X" will result in the majority of the customers remaining unserved until the failure is resolved. The tie as positioned in Fig. 2 serves no benefit for failures beyond the first switch. However, if the tie is placed at the end of the circuit as illustrated in Fig. 3, it gives a far greater benefit to reducing unserved energy.

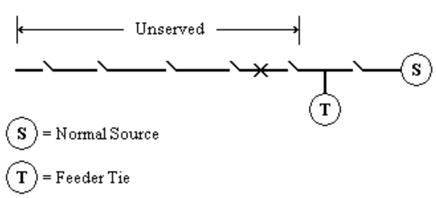


Fig. 2. Tie location near source

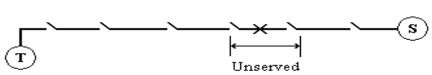


Fig. 3. End of feeder tie location

The same argument illustrated in Fig. 2 and 3 for one feeder tie also applies for circuits with more than one tie when there is a limited capacity on each tie. An example of this for a circuit with two feeder ties is illustrated in Fig. 4. Assume for this example, that each tie has enough available capacity to serve two sections of the original feeder. As shown in Fig. 4, a failure located at "X" would lead to a large amount of unserved energy because the tie at the end of the circuit does not have enough capacity to pick up more than the last two sections of the feeder. However, if the ties are evenly spaced as shown in Fig. 5, every section can retain service except the one directly affected by the fault.

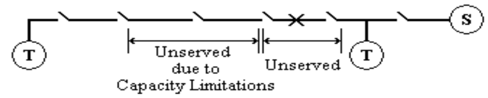


Fig. 4. Two feeder ties unevenly spaced

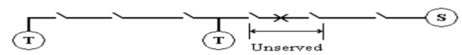


Fig. 5. Two feeder ties evenly spaced

V. CONCLUSIONS

This paper presented value-based probabilistic urban distribution system planning models for determination of optimal section length for switch placement on the main feeder, number and placement of feeder ties, and feeder and transformer loadings. The following conclusions were reached based upon the assumed failure rates, repair times, switching time, and customer value of reliability used in the analyses. A sectionalizing switch should be placed every 0.7 MW of feeder load or approximately every ¼ mile. Two feeder ties should be installed on a radial feeder with no three-phase branches and with no voltage constraints. The most essential tie, in terms of reliability, is the tie located at the end of the feeder. This tie allows the most flexibility because it can provide backup for a failure anywhere along the feeder. Available transformer capacity (top nameplate rating) should be utilized for normal loading conditions. Feeders should be loaded to approximately 8 MVA, leaving 3 to 4 MVA available in emergency. Having sufficient feeder tie capacity on adjacent feeders is essential for providing backup capacity following a transformer outage, and more importantly for backup following feeder outages, which occur more frequently.

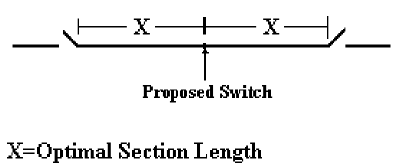
VI. APPENDICES

APPENDIX A
Finding Optimum Section Length

Assumptions:

1. Feeder load is uniformly distributed at 2500 kW per mile of three-phase
2. All load can be picked up once failure is isolated

The illustration below shows a section where a switch will be added to form 2 sections each of length X.



The annual benefit of this improvement is the reduction in unserved energy costs. The following is a mathematical derivation of the benefit in terms of the desired section length, ‘x’.

Definition of Terms:

$x - Section\ Length\ in\ miles$

$UE - Unserved\ Energy\ in\ kWh$

$F_{Line} - Failure\ Rate\ of\ Line\ in\ {}^{events}\!/_{mile\text{-}year}$

$RT_{Line} - Repair\ Time\ of\ Line\ in\ Hours$

$F_{Switch} - Failure\ Rate\ of\ Line\ Switch\ in\ {}^{events}\!/_{year}$

$RT_{Switch} - Repair\ Time\ of\ Switch\ in\ Hours$

$Load_{Total} - Total\ Feeder\ Load\ in\ kW$

$T_{Switching} - Time\ Required\ to\ Isolate\ Failure\ and\ Close\ Ties\ in\ Hours$

$(T_{Switching} = 70 \text{ minutes} = 1.166 \text{ hours})$

$$Benefit = \Delta UE * {}^{Cost}\!/_{kWh} = (UE_{Old} - UE_{New}) * {}^{Cost}\!/_{kWh}$$

$$UE_{Old} = (2x * F_{Line})(2x * {}^{kW}\!/_{mile}) * RT_{Line}$$

$$UE_{New} = (x * F_{Line})(x * {}^{kW}\!/_{mile}) * RT_{Line} + (x * F_{Line})(x * {}^{kW}\!/_{mile}) * T_{Switching}$$
$$+ (x * F_{Line})(x * {}^{kW}\!/_{mile}) * RT_{Line} + (x * F_{Line})(x * {}^{kW}\!/_{mile}) * T_{Switching}$$
$$+ (F_{Switch})(2x * {}^{kW}\!/_{mile}) * RT_{Switch} + (F_{Switch})(Load_{Total}) * T_{Switching}$$

The failure rates and repair times listed in Table A-I can be used in the calculations.

TABLE A-I
COMPONENT FAILURE RATES & REPAIR TIMES

Component	Failure Rate (F)	Repair Time (RT)
3phase OH	0.8/mi-yr	4 hours
Switch	0.001/yr	5.5 hours

Substituting the failure rates and repair times along with assumed constants into the previous equations results in the following:

$$UE_{Old} = (2x * .8)(2x * 2500) * 4$$
$$UE_{Old} = 32000x^2\ kWh$$
$$UE_{New} = (x * .8)(x * 2500) * 4 + (x * .8)(x * 2500) * 1.166$$
$$+ (x * .8)(x * 2500) * 4 + (x * .8)(x * 2500) * 1.166$$
$$+ (.001)(2x * 2500) * 5.5 + (.001)(10000) * 1.166$$
$$UE_{New} = 20666.7x^2 + 27.5x + 11.67\ kWh$$
$$\Delta UE = 32000x^2 - (20666.7x^2 + 27.5x + 11.67)\ kWh$$
$$\Delta UE = 11333.3x^2 - 27.5x - 11.67\ kWhr$$
$$\Delta UE * {}^{\$10.76}\!/_{kWh} = 121{,}946.7x^2 - 295.9x - 125.5$$

The cost of a switch plus installation was estimated to be $5,000. Using UCBM, the 30-year present worth of that investment was calculated to be $8481. Setting the cost equal to the annual reliability benefit to customers and solving for ‘x’, will give the desired section length for a one-year payback as shown in the equation below. The terms can also be multiplied by the appropriate factors to obtain the desired section length for two-year payback and so on.

$$121{,}946.7x^2 - 295.9x - 125.5 = 8481$$

APPENDIX B

Feeder & Transformer Loading

Feeder tie and bus tie capacity used for these simulations were calculated using the following equation:

$$Feeder\ Tie\ Capacity = Feeder\ Emergency\ Rating - Feeder\ Peak\ Load$$

Bus tie capacity = (Xfmr emergency rating – Xfmr load level)/# of feeders per Xfmr

The feeder tie capacity is equal to the emergency rating minus the feeder peak load level, assuming an ampacity limited feeder. For a typical feeder the normal rating is 10 MVA, and the emergency rating is 11.6 MVA. The emergency rating for a new 33 MVA transformer was calculated using PT Load. Results showed that the transformer could be loaded to 48 MVA, assuming a typical MidAmerican daily load curve. The PT Load studies were performed for a 24-hour period, which was taken to be the time required for a mobile sub to be installed.

When simulating a transformer failure in DISREL, it was assumed that the bus tie capacity was split up evenly among the circuits fed from a transformer. This was necessary because simulations were run on a per feeder basis, so assigning the total bus tie capacity to the feeder being simulated would underestimate the total unserved energy associated with a transformer failure. Splitting the bus tie capacity evenly represents the fact that for a transformer failure, the bus tie to the other transformer is able to pick up only a percentage of the total transformer load. The table below shows the results of the DISREL simulations and the UCBM calculations.

$$Circuit\ Length = 2.25 + (FeederMVA - 6) * .2$$
$$XfmrLoad = \#of\ Feeders * FeederMVA$$
$$UE\ for\ 33MVA = \#of\ Feeders * \left[UE_{perFeeder} + \frac{(33 - XfmrLoad)}{FeederMVA}\right]$$
$$Yearly\ Benefit = UE_{11MVA\,System} - UE_{Alternative\ System}$$

The capacity charges used were the same ones used for second source calculations. They are listed below.

$$Xfmr\ Capacity\ Cost = {}^{\$29{,}632}\!/_{MVA}$$
$$Feeder\ Capacity\ Cost = {}^{\$9{,}146}\!/_{MVA}$$

The equations used to calculate the capacity charge for the total system are as follows for feeder capacities of 10 MVA and below:

$$Feeder\ Capacity\ Cost = \#of\ Feeders * (10MVA - FeederMVA) * \$9{,}146$$
$$Xfmr\ Capacity\ Cost = (33 - (\#of\ Feeders * FeederMVA)) * \$29{,}632$$
$$Unused\ Capacity\ Cost = Feeder\ Capacity\ Cost + Xfmr\ Capacity\ Cost$$

Using the ‘Annual Benefit’ and the ‘Unused Capacity Cost’, a cost-benefit analysis can be performed on each scenario, which takes into account customer value of reliability. The option with the shortest payback period is the desired alternative. The results in Table IV in Section IV show that four 8 MVA circuits is the alternative with the shortest payback period.

APPENDIX C
Feeder Tie Cost Calculation

To find the construction cost of the three-phase line that is required for a feeder tie, the distance between the two circuits must be calculated. That number can then be multiplied by the cost per mile of three-phase construction. Assuming a two- transformer substation with four feeders per transformer, area served will be split into 1/8ths, as indicated in the Fig. C-1. Each line emanating from the center represents a feeder.

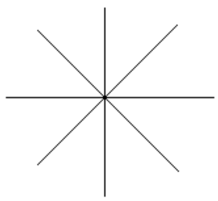
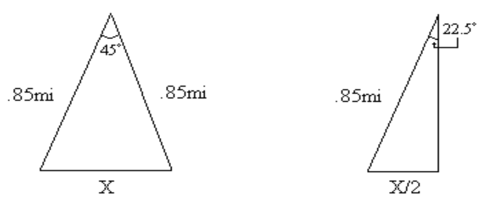


Fig. C-1. Service area split into 1/8ths

Assuming a 1.75-mile radius for the substation, the following figures represents a tie placed at the midpoint of a feeder.



$$\sin 22.5° = \frac{X/2}{.85}$$
$$X = 2 * .85 * \sin 22.5°$$
$$X = .55 miles$$

$$Cost = \$30{,}487/mile * .55 miles$$
$$Cost = \$16768$$
$$Cost\ Per\ Feeder = \$16768/2 = \$8384$$

APPENDIX D
Affects of Tie Maintenance

In order to model a more accurate representation of adding a second feeder tie to circuit, the affect of feeder tie maintenance had to be included. Different frequencies of tie maintenance were selected, which allowed the tie availability to be calculated. The tie availability was used to calculate a new unserved energy cost for Case 2 (single feeder tie). If the feeder tie is available, the system remains the same as Case 2, which has an unserved energy cost of \$96,561. If the feeder tie is unavailable, the system looks has an unserved energy cost of \$272,489. Multiplying each of these by the correct factor and then adding the results will give the modified unserved energy cost for Case 2 with maintenance affects included. The equation used to arrive at the modified unserved energy cost is listed below.

$$UE_{New} = TieAvailability * \$96{,}561 + (1 - TieAvailability) * \$272{,}489$$

Table D-I lists various frequencies of maintenance. The maintenance duration of 672 hours corresponds to 4 weeks. The tie availability and corresponding UE costs are also listed.

TABLE D-I
FREQUENCIES OF MAINTENANCE

Maint Duration (hours)	Frequency (once every N years)	Tie Availability	New UE Cost of Case 2
672	1	92.3%	\$158,879
672	3	97.4%	\$151,087
672	5	98.5%	\$149,528
672	10	99.2%	\$148,360
672	15	99.5%	\$147,970

The new unserved energy cost of Case 2 (single feeder tie) can then be compared against the unserved energy cost of the case with two feeder ties (\$96,303) to determine the benefit of adding the second tie. Table VI in section IV shows the yearly benefit associated with each maintenance frequency for the addition of a second feeder tie. These values were used in UCBM to determine the payback period for the incremental investment taking into account customer value of improved reliability.

APPENDIX E
Additional Ties for Feeders with Three-Phase Branches

The benefit to adding a tie at the end of a three-phase branch is that for line or switch failures, only the section which failed will be unserved during repair instead of all downstream sections in the case of no backup tie. Fig. E-1 illustrates this concept.

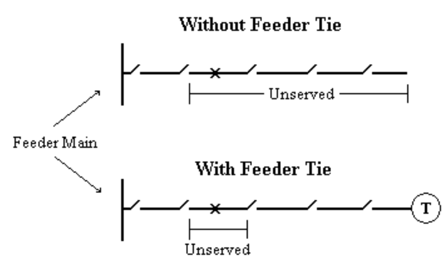


Fig. E-1. Benefit of tie for three-phase branch

If following two assumptions are made, an equation can be developed for the benefit of installing the additional feeder tie:

1. Feeder load is uniformly distributed at 2500 kW per mile of three-phase

2. All load can be picked up once failure is isolated

The method used in developing the equation was to calculate the reduction in unserved energy for a fault on each section and each switch on the branch. For example, for a fault on the second section of the branch as depicted in the Figure 1, four sections will be unserved if there is no feeder tie, and only one section will be unserved if there is a feeder tie. The three sections that are served in the case with the feeder tie, are not picked back up instantaneously, instead they are out for the time it takes to isolate the failure and close the backup tie. Therefore the load on those three sections will be unserved for a smaller amount of time if the backup tie is available.

In order to apply this to a branch with 'n' sections, the change in unserved energy for a fault on each individual section and switch needs to be calculated. The following equation calculates the change in unserved energy for faults on each section.

Definition of Terms:

$n - Number\ of\ Sections$

$UE - Unserved\ Energy\ in\ kWhr$

$F_{Line} - Failure\ Rate\ of\ Line\ in\ {}^{events}/_{mile-year}$

$RT_{Line} - Repair\ Time\ of\ Line\ in\ Hours$

$F_{Switch} - Failure\ Rate\ of\ Line\ Switch\ in\ {}^{events}/_{year}$

$RT_{Switch} - Repair\ Time\ of\ Switch\ in\ Hours$

$T_{Switching} - Time\ Required\ to\ Isolate\ Failure\ and\ Close\ Ties\ in\ Hours$

$$\begin{aligned}\Delta UE &= Section\ Length * F_{Line} * {}^{kW}/_{mile} * Section\ Length * (n-1) * (RT_{Line} - T_{Switching}) \quad \leftarrow 1st\ section \\ &+ Section\ Length * F_{Line} * {}^{kW}/_{mile} * Section\ Length * (n-2) * (RT_{Line} - T_{Switching}) \quad \leftarrow 2nd\ section \\ &+ Section\ Length * F_{Line} * {}^{kW}/_{mile} * Section\ Length * (n-3) * (RT_{Line} - T_{Switching}) \quad \leftarrow 3rd\ section\end{aligned}$$

Factoring out some like terms, the equation can be simplified to

$$\Delta UE = Section\ Length^2 * F_{Line} * {}^{kW}/_{mile} * (RT_{Switch} - T_{Switching})[n-1+n-2+n-3+.....+1]$$

$$\Delta UE_{Sections} = Section\ Length^2 * F_{Line} * {}^{kW}/_{mile} * (RT_{Switch} - T_{Switching}) * \sum_{i=0}^{n-1} n-(i+1)$$

A similar approach is used to determine the change in unserved energy associated with switch failures, and the equation below is arrived at.

$$\Delta UE_{Switches} = F_{Switch} * {}^{kW}/_{mile} * Section\ Length * (RT_{Switch} - T_{Switching}) * \sum_{i=0}^{n-1} n-(i+1)$$

To obtain the total change in unserved energy from adding the switch, the previous two equations can be added. Table VII in Section IV summarizes the benefits associated with adding a feeder tie at the end of a three-phase branch for various branch lengths.

VII. References

[1] A. A. Chowdhury, S. K. Agarwal and D. O. Koval, "Reliability Modeling of Distributed Generation in Conventional Distribution Systems Planning and Analysis", IEEE Transactions on Industrial Applications, Vol. 39, Number 5, September/October 2003, pp. 1493-1498.

[2] A. A. Chowdhury and D. O. Koval, "Value-Based distribution system reliability planning", *IEEE / IAS Transactions*, Volume 34, No. 1, pp. 23-29, Jan./Feb. 1998.

[3] A. A. Chowdhury and D. O. Koval, "Application of customer interruption costs in transmission network reliability planning", *IEEE Transactions on Industry Applications*, Volume 37, No. 6, pp. 1590-1596, Nov./Dec. 2001.

[4] R. Billinton and P. Wang, "Distribution reliability cost/worth analysis using analytical and sequential simulation techniques", IEEE Transactions on Power Systems, Vol. 13, No. 4, November 1998, pp. 12451250.

[5] R. E. Brown, S. Gupta, R. D. Christie, S. S. Venkata and R. Fletcher, "A. A. Chowdhury, D. O. Koval, "Automated primary distribution system design: reliability and cost optimization", IEEE Transactions on Power Delivery, Vol. 12, No. 2, April 1997, pp. 1017-1022.

[6] A. A. Chowdhury and D. O. Koval, "Current practices and customer value-based distribution System Reliability Planning", Transactions of the IEEE/IAS Annual Meeting, Volume 2, Rome, Italy, October 8 – 12, 2000, pp. 909-916.

[7] R. E. Brown and M. M. Marshall, "Budget constrained planning to optimize power system reliability", IEEE Transactions on Power Systems, Vol. 15, No. 2, May 2000, pp. 887-892.

[8] R. E. Brown, "The impact of heuristic initialization on distribution system reliability optimization", International Journal of Engineering Intelligent Systems for Electrical Engineering and Communications, Vol. 8, No. 1, March 2000, pp. 45-52.

[9] Electric Power Research Institute, Utilitiy cost benefit analysis model (UCBM), EPRI RP1678-15, March 1987.