

Reliability Modeling of Distributed Generation in Conventional Distribution Systems Planning and Analysis

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Abstract—The primary objective of any electric utility company in the new competitive environment would be to increase the market value of the services it provides with the right amount of reliability, and at the same time, lower its costs for operation, maintenance, and construction of new facilities in order to provide lower rates for customers. The electric utility company will strive to achieve this objective via many different means, one of which is to defer the capital distribution facility requirements in favor of a distributed generation (DG) solution by an independent power producer (IPP) to meet the growing customer load demand. In this case, the distribution capital investment deferral credit received by the IPP will be dependent on the incremental system reliability improvement rendered by the DG solution. In other words, the size, location and the reliability of the DG will be based on the comparable incremental reliability provided by the distribution solution under considerations. This paper presents a reliability model for determining the DG equivalence to a distribution facility for use in distribution system planning studies in the new competitive environment.

Index Terms—Distributed generation (DG), distribution capital deferral, generation equivalence, independent power producer (IPP), reliability.

I. INTRODUCTION

AT PRESENT, the electric power industry is undergoing considerable change with respect to structure, operation, and regulation [1]–[3]. The various electric utility acts introduced in different countries have initiated the restructuring process and the traditional vertically integrated utility structure consisting of generation, transmission and distribution functions has been dismantled. Instead, distinct generation, transmission, and distribution companies have been established in which each company performs a single function in the overall electricity supply task. As a result, the overall responsibility of serving the individual customer needs does no longer reside

in a single electric utility, as was the case in the vertically integrated utility structure.

In order to appreciate the reliability issues arising in the present electric power industry environment, it is necessary to recognize the many faces and actions that are shaping the environment [1]. The deregulation legislations establish the many new entities to facilitate system operations and market functions independent of owners of facilities. In the new competitive environment, power generation is no longer a natural monopoly. Generation expansion will be decided by the market forces and new players such as independent power producers (IPPs) and cogenerators will make their presence felt in the generation arena.

As customers will increasingly demand lower rates and higher reliability in the new competitive environment, the challenging task of a electric utility company will be to minimize the capital investments and operation and maintenance expenditures to hold down electricity rates. If, however, the cost is cut too far, it may jeopardize the system's ability to supply reliable power to its customers. The movement toward deregulation will therefore introduce a wide range of reliability issues that will require system reliability criteria and tools that can incorporate the residual risks and uncertainties in distribution system planning and operating. Probabilistic techniques offer a rational response to these conflicting new requirements. This paper presents a probabilistic reliability based distribution system expansion and investment model to satisfy increasing customer demands of lower rates and higher service reliability in the competitive market. Reference [4] presents a similar Monte Carlo simulation-based probabilistic approach to determining generation equivalence to a transmission facility.

II. PROBLEM DEFINITION

Distribution system reliability is an important issue in system planning and operating. In the past, electric utilities were continuously adding more facilities to their systems in order to satisfy the increasing customer load requirements. An electric utility company traditionally has relied on a set of deterministic criteria to guide distribution planning. Such criteria specify outage conditions under which the system must meet future load forecasts. In most cases, the systems were over built resulting in higher electricity rates for customers. As customers become more cost and service sensitive in the emerging competitive market, it will

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become extremely difficult for distribution companies to rationalize capital expenditures on the basis of deterministic criteria. The distribution companies will be forced to look for different means to avert the risk of over investment in the system in providing competitive rates and acceptable reliability levels to customers. As load increases, the distribution system has to be expanded to satisfy increased customer load requirements. For example, due to the increased load growth to a specific area of a distribution system, the local area distribution network is deemed to be inadequate and requires expansion. The distribution system planners would come up with a number of local area distribution improvement solutions such as adding a distribution feeder, adding a reactive compensation to the area or adding a distribution substation to meet the growing customer loads. The cost of capital will be added to the rate base and will be reflected on the electricity rates.

In order to remain competitive, the electric utility company will look for ways to reduce costs and still provide the acceptable level of reliability required by the customers. As mentioned earlier, smaller and environmentally friendlier distributed generation (DG) can now be built economically by independent generators. DG consists of small generators typically ranging in capacity from 15 to 10 000 kW connected to the electric distribution system [5]. DG can be installed at utility or at customer sites. DG technologies include conventional and nonconventional energy technologies such as diesel engine driven generators, wind turbines, fuel cells, and microturbines. Recent technical advances have significantly reduced the cost of DG and could eventually compete with gas turbines. Reference [6] indicates that a generator selling into the real-time market could have made more than \$3068/MWh during just 5 h on July 21, and would have made more than twice as much money if it could have earned the real-time price on the days when the real-time price averaged more than \$35/MWh. Reference [7] indicates that in the next 10 to 15 years DG could capture 10%–15% of new generating capacity in the U.S. The growing demand for power could reach 60 000–120 000 MW of generation over the next 10–15 years of which DG will be an increasing component. This could amount to 6000–12 000 MW of DG over 10–15 years of DG. Reference [8] presents a probabilistic area investment model for the determination of whether or not DG is an economic option in the overall distribution system expansion planning.

Reference [9] states that many DG technologies are expected to see 25%–40% decreases in capital costs and 10%–15% increases in efficiency. In addition, [9] predicts that over the next ten years, DG will emerge worldwide in many different shapes and sizes, possibly accounting for 8%–14% of all additions.

In light of the above discussions, one prudent investment decision by the electric utility company in the competitive market would be to issue a request for proposal of DG addition by an IPP to mitigate the distribution deficiency in the system. In this case, the distribution requirements can be met by a generation solution and significant savings through capital deferral by the electric utility company can be achieved, thus enabling the company to hold the line on rates. The IPP would receive incentives in the form of capital deferral credit from the electric utility company for replacing a distribution facility requirement. The

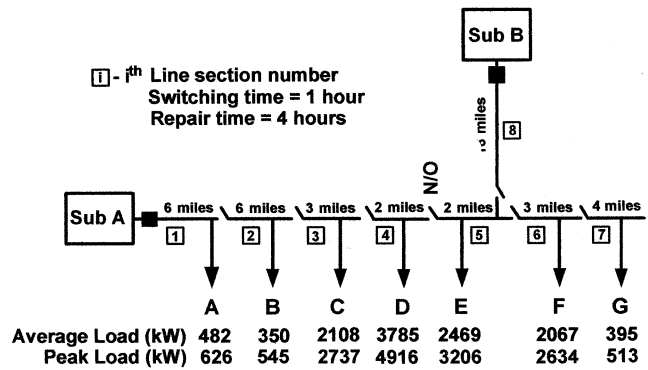


Fig. 1. Distribution radial network configuration showing peak and average loads at each load point.

amount of the capital deferral credit received by the IPP would be negotiated between the electric utility company and the IPP based on the size of the generator, the amount of must-run capacity from the unit to satisfy distribution requirements, and the comparable reliability improvement to the area where the generator will be located. This paper illustrates a reliability model to determine the DG equivalence to a distribution facility based on comparable reliability rendered by distribution and generation solutions using a small illustrative distribution system.

III. ILLUSTRATIVE DISTRIBUTION SYSTEM CONFIGURATION CHARACTERISTICS

The basic objective of the paper is to present a reliability model to determine DG equivalence to a distribution facility in an attempt to improve the distribution system reliability while meeting increasing customer load requirements. This paper considers a simple illustrative distribution system loading conditions and needed reinforcements. The load of the distribution system is supplied by two 13-kV distribution feeder circuits as shown in Fig. 1.

The 13-kV feeder from Substation A and Substation B are operated as radial feeders but they can be interconnected by a normally open tie point. The disconnects, lateral distributors, step-down transformers, fuses, and the alternate supply are assumed to be 100% available in the analysis to illustrate the reliability model.

The load factor for the service area is assumed to be 77%. The loading conditions at each load point are shown in Fig. 1. The peak rating for the 13 kV feeders from Substation A and Substation B are 12.00 and 10.5 MVA at a power factor of 0.90 lagging. The 13-kV feeder failure rate is assumed to be 2.0 failures per 100 mi per year. In order to evaluate the load point reliability levels of the distribution system, it is essential to have working knowledge base of the operation of the feeder circuits and their operational constraints. The feeders can supply their respective loads when operated radially. For a line section outage on either feeder, the healthy feeder can not supply the entire load of the faulted feeder due to the fact that the feeders are thermally limited. In this case, if both feeders are operated radially and are tied through a normally open tie switch, then any line section outage can be manually isolated and the load on the remaining line sections must be evaluated as to whether portions of the load can

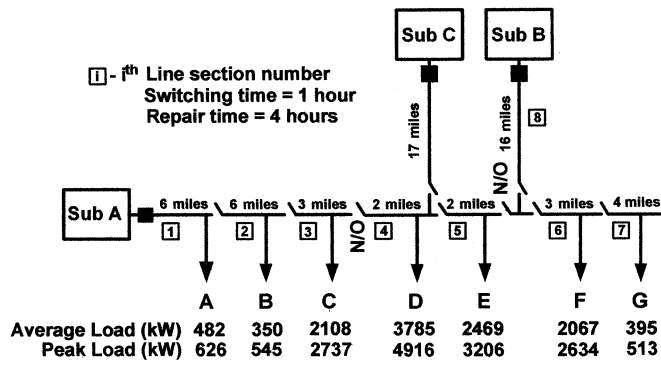


Fig. 2. Distribution radial network configuration showing a third feeder from Substation C to the area.

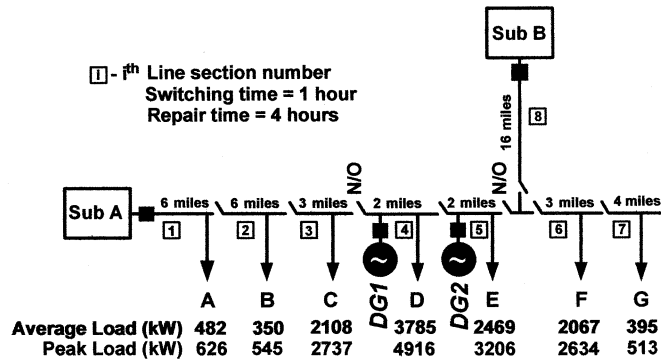


Fig. 3. Distribution radial network configuration showing two DG additions at load points D and E.

be interrupted, i.e., shed and what loads can be energized from the alternate feeder. In this case example, only portions of the loads “D” and “E” can be supplied from the alternative feeder.

To address the feeder limitation issues, a third feeder from an adjacent Substation C to the area has been evaluated. The feeder rating is 12.0 MVA, similar to the feeder from Substation A. The length of the third feeder is 17 mi as shown in Fig. 2. In normal operation of the local distribution system, it is assumed that the feeders from Substation A and Substation B will be off-loaded by transferring loads D and E to the third feeder. For simplicity, it will be assumed that the duration to repair any line section is an average of 4.0 h and the duration to perform the necessary isolation, switching, and load transfer activities to be an average of 1.0 h. In this paper, multiple contingency outages are neglected and the emphasis is placed on illustrating the reliability-based determination of DG equivalence to a distribution facility. Before proceeding with this third feeder solution to solve the capacity problem, the prudent decision by the electric utility company would be to seek alternative proposals for DG or other solutions which adequately expand the distribution capacity in the area. In this case, the capital cost of the third feeder could be avoided or deferred, thereby holding the line on customer rates. The DG solution is illustrated in Fig. 3.

Although the DG solution is the expensive solution compare to the distribution solution, it has the side benefit of providing much needed voltage control, and the cost borne by the IPP would be much less, as the IPP would receive the distribution capacity deferral credit, which is a percentage of the annual revenue requirements of the distribution solution. In the request for

proposals, the electric utility company would identify the minimum capacity of the unit based on the incremental reliability provided by the distribution solution. The following section describes the probabilistic reliability technique for determining the equivalent capacity for a distributed generating unit(s) that would replace the requirements of the third feeder from the Substation C to the area.

IV. RELIABILITY ASSESSMENT MODEL

Reliability analyses of power systems are conventionally done by using either the analytical method based on the contingency enumeration approach or Monte Carlo simulation. The analytical approach based on contingency enumeration can identify low voltage and voltage collapse problems in addition to thermal overloads. The enumeration method however cannot model a wide range of operating conditions and is therefore subject to different simplifying assumptions. Monte Carlo simulation, on the contrary, is capable of modeling the full range of operating conditions. One disadvantage of this model is that computer resource limitations limit the solution precision to dc power flow problems. In this case, the simulated performance indexes reflect only system overload problems. The important but extreme low-probability transmission outages as well as low voltage and voltage collapse problems cannot be modeled in this method.

General Reliability’s DISREL [10] program is utilized in this paper in determining DG equivalence to the third feeder addition to the area shown in Fig. 1. The program is designed to aid electric utility and industrial/commercial customers with predictive reliability assessment of a distribution network. The customer-responsive utility would address reliability problems by selecting project alternatives that have the highest internal and external benefits. Customers may be willing to share the costs when approached with quantifiable plans. In addition, it can assist in developing reliability guidelines and service-based pricing by quantifying the system reliability. DISREL computes a set of reliability indexes including SAIFI, SAIDI, ASAI, load/energy curtailed, and the cost of outages based on the component outage data and the cost of interruption to a customer. The program models time-sequenced switching actions taken by an operator/repair person following an outage. It can also be used to quantify benefits of automating distribution systems, feeder reconfiguration, and to compare various competing projects using cost of outages and utility benefits. Typical outage data for major components and the cost of interruption data for different types of customer are supplied with the DISREL program.

A. Reliability Indexes

The program computes a set of reliability indexes that have been recommended in various publications [1]–[3]. Some of the load point indexes computed are as follows:

- 1) frequency of load interruptions (occurrences per year);
- 2) duration of load interruptions (hours per occurrence);
- 3) duration of load interruptions (hours per year);
- 4) frequency of customer interruptions (customer interruptions per year);

TABLE I
DISTRIBUTION NETWORK GENERATION AND FEEDER RELIABILITY DATA

Component	Failure rate occ/year	Repair time, hours	Switching time, minutes	Stuck probability
Substation A	0.02	4.0	60.0	
Substation B	0.02	4.0	60.0	
Substation C	0.02	4.0	60.0	
DG1 at D	5.00	50.0	60.0	
DG2 at E	5.00	50.0	60.0	
Section 1	0.12	4.0	60.0	
Section 2	0.12	4.0	60.0	
Section 3	0.06	4.0	60.0	
Section 4	0.04	4.0	60.0	
Section 5	0.04	4.0	60.0	
Section 6	0.06	4.0	60.0	
Section 7	0.08	4.0	60.0	
Third feeder	0.32	4.0	60.0	
Sub A breaker	0.0036	12.0	60.0	0.01
Sub B breaker	0.0036	12.0	60.0	0.01
Sub C breaker	0.0036	12.0	60.0	0.01

- 5) duration of customer interruptions (customer hours per year);
- 6) Expected Unsupplied Energy (EUE) in kilowatthours per year;
- 7) expected outage cost in dollars.

DISREL also computes indexes for the system under study.

A list of system indexes is as follows:

- 1) System Average Interruption Frequency Index (SAIFI);
- 2) System Average Interruption Duration Index (SAIDI);
- 3) Customer Average Interruption Frequency Index (CAIFI);
- 4) Average Service Availability Index (ASAI);
- 5) Average Service Unavailability Index (ASUI);
- 6) EUE (in kilowatthours per year);
- 7) expected outage cost in dollars (\$).

B. Reliability Data

The input data and assumptions used to assess the reliability improvements by the distribution solution and the size of the distributed generator alternative providing the equivalent reliability enhancement to the distribution system shown in Fig. 1 are presented in Table I.

V. DISCUSSION OF RESULTS

The study begins by constructing the existing system with the added third feeder from Substation C to the area served by the distribution system shown in Fig. 1 and then computing the reliability of the area. The second step is to determine the size of a distributed generator or combination of smaller distributed units by adding to the existing system that would provide the similar reliability level for the area.

As mentioned earlier, the distribution reinforcement to the area considered is a 17-mi-long 13-kV feeder from Substation C to the area of concern served by the distribution system shown in Fig. 1. The assumed reliability data for this feeder used in the simulation are shown in Table I.

A. Equivalent DG Reinforcement Alternative

In order to compute the amount of DG capacity providing the reliability enhancement identical to that of the 13-kV feeder, a range of capacities from 1 to 6 MW were considered in the studies. The assumed reliability data for the distributed generators used in the studies are shown in Table I.

The reliability index chosen based on which to determine the size of the equivalent generator(s) is Expected Energy Not Served (EENS). EENS adds the dimension of magnitude in terms of the energy curtailed and is expressed in kilowatthours per year. The computed EENS indexes for the existing configuration, the distribution reinforcement, and different DG reinforcements are summarized in Table II.

The computed EENS results presented in Table II indicate that adding a third feeder greatly improves the reliability of the existing system. The EENS reduces to almost one-fourth when a third feeder is added. In order to get the same reduction in EENS by adding DGs, a number of combinations were considered. Results are presented for adding DGs of various sizes. One 6-MW DG or two smaller 3-MW DGs yield almost similar reliability improvement of distribution reinforcement to the distribution system. However, it is preferred to connect two smaller units as they will provide higher reliability. The difference in EENS is more pronounced if higher level outages are also considered. In this example, the location of the unit is not making any difference to reliability, but in real life it is important to include location of the unit in comparing various options.

The probabilistic method presented in the paper permits to identify the best location for the units in the local area and the minimum output requirements of the distributed generator(s) depending on the area load and system conditions. The computation of the reliability based equivalent DG capacity to replace a distribution reinforcement requirements would provide important input to economic feasibility studies performed by the IPP willing to penetrate into the new generation market. It is a well-known fact that smaller, distributed and environmentally

TABLE II
EENS RESULTS FOR EXISTING CONFIGURATION, THIRD FEEDER ADDITION, AND DG REINFORCEMENTS FOR THE DISTRIBUTION NETWORK CONSIDERED

EENS, kWh per year						
Existing Distribution Configuration	Distribution Feeder Reinforcement Third Feeder Addition	Distributed Generation Reinforcement				
		One 1 MW DG at "D" and one 1 MW DG at "E"	One 2 MW DG at "D" and one 2 MW DG at "E"	One 3 MW DG at "D" and one 3 MW DG at "E"	One 6 MW DG at "D"	One 6 MW DG at "E"
17,416	4,660	11,426	6,639	4,628	4,630	4,630

friendly distributed generators hold much promise in the generation of future electric energy as opposed to large and centralized coal and nuclear fired units. In addition, smaller units are more suited to replace distribution capacity requirements as illustrated in this paper. More over, the smaller units have the economic advantage of receiving distribution capital deferral credit by replacing distribution requirements.

VI. CONCLUSION

The concepts and applications of a probabilistic reliability model for computing DG equivalence to a distribution facility in the deregulated electric utility environment is presented in the paper. Local area distribution reliability planning is a powerful methodology especially when the area capacity improvement options are disparate. One important conclusion of this paper is that while the distribution generation addition may be the most expensive alternative, with the right generator size determined using the reliability techniques and the distribution capital deferral credit obtained from the utility company, the DG option could become a cost-effective solution to the energy supply problem of the future benefiting both the energy suppliers and the energy consumers. Finally, the methodology can be effectively used in the emerging competitive electric energy market to evaluate a wide range of power supply problems.

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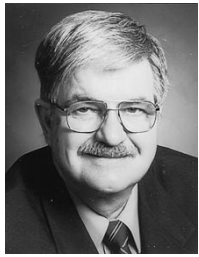


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