

# 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 is to increase the market value of the services by providing 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.

**Key Words:** Reliability, distributed generation, independent power producer, generation equivalence, distribution capital deferral.

## 1.0 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 forces 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 IPP and co-

generators 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 is 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 towards deregulation will therefore introduce a wide range of reliability issues that 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.

## 2.0 PROBLEM DEFINITION

Distribution system reliability is an important issue in system planning and operations. 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 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 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 in 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. One solution is to add smaller and environmentally friendlier distributed generation (DG) which can now be built economically by independent generators. Distributed generation 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. Distributed generation technologies include conventional and non-conventional energy solutions 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 notes that a generator selling into the real-time market could have made more than \$3,068/MWh during just 5 hours 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% to 15% of new generating capacity in the United States. The growing demand for power could reach 60,000 to 120,000 MW of generation over the next 10 to 15 years of which DG will be an increasing component. This could amount to 6,000 to 12,000 MW of DG over 10 to 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, Reference 9 predicts that over the next 10 years, DG will emerge worldwide in many different shapes and sizes, possibly accounting for 8-14% of all additions

In the light of above discussions, one prudent investment decision by an electric utility company in the competitive market would be to issue a request for proposal of distributed generation 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 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 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.

### 3.0 ILLUSTRATIVE DISTRIBUTION SYSTEM CONFIGURATION CHARACTERISTICS

The basic objective of the paper is to present a reliability model to determine distributed generation 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 Figure 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 one hundred per cent available in the analysis to illustrate the reliability model.

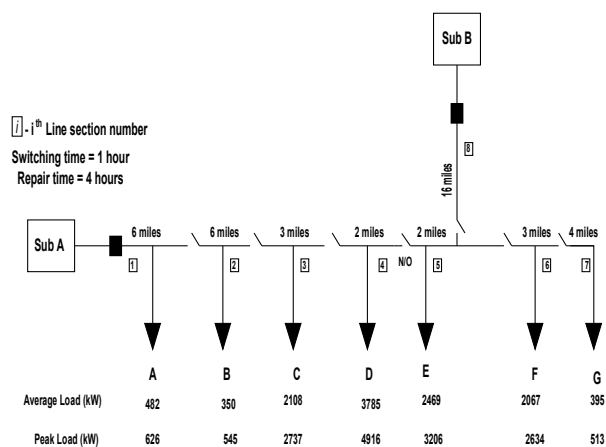


Figure 1: Distribution radial network configuration showing peak and average loads at each load point

The load factor for the service area is assumed to be 77%. The loading conditions at each load point are shown in Figure 1. The peak rating for the 13 kV feeders from Substation A and Substation B are 12.00 MVA and 10.5 MVA at a power factor of 0.90 lagging. 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 cannot 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 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 added. The feeder rating is 12.0 MVA, similar to the Feeder from Substation A. The length of this feeder is 17 miles as shown in Figure 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 average duration to repair any line section is 4.0 hours and the duration to perform the necessary isolation, switching and load transfer activities is 1.0 hour. In this paper, 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 electric utility company should also explore alternative proposals for distributed generation 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 Figure 3.

Although, the DG solution is expensive solution compared 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.

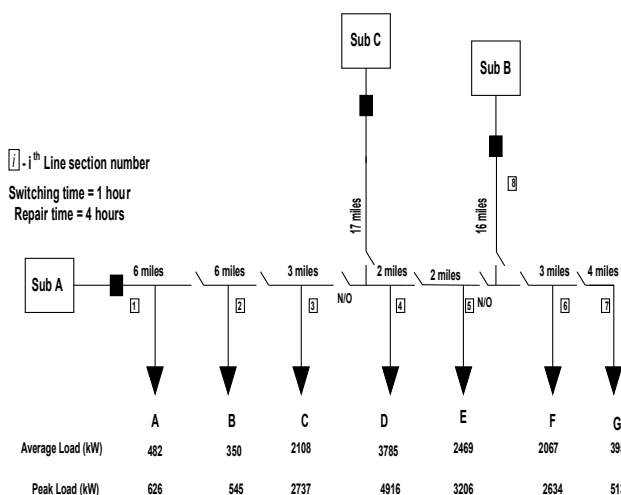


Figure 2: Distribution radial network configuration showing a third feeder from Substation C to the area

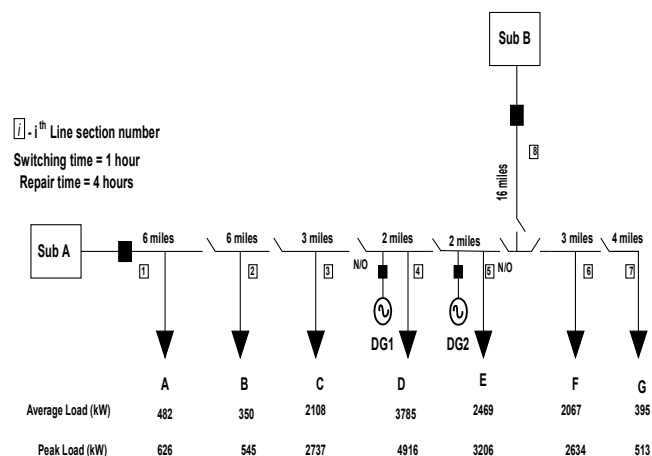


Figure 3: Distribution radial network configuration showing two DG additions at load points D and E

#### 4.0 RELIABILITY ASSESSMENT MODEL

Reliability analysis of an electric distribution system is 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 indices reflect only system over load 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 Figure 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. DISREL computes a set of reliability indices 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 is supplied with the DISREL program.

**4.1 Reliability Indices**

The program computes a set of reliability indices that have been recommended in various publications [1-3]. Some of the load point indices 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)
5. Duration of customer interruptions (customer-hours per year)
6. Expected Unsupplied Energy (EUE in kWh per year)
7. Expected outage cost in dollars

DISREL also computes indices for the system under study. A list of system indices 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. Expected Unsupplied Energy (EUE in kWh per year)
7. Expected outage cost in dollars (\$)

**4.2 Reliability Data**

The input data used in quantifying the reliability improvements due to the distribution solution and different distributed generator alternatives to match the equivalent reliability enhancements to the distribution system shown in Figure 1 is presented in Table 1.

**5.0 DISCUSSION OF RESULTS**

The study begins by first determining the reliability of the existing system. Next, reliability indices are calculated after adding a third feeder from Substation C to the area served by the distribution system shown in Figure 1. The last 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-mile long 13 kV feeder from Substation C to the area of concern served by the distribution system shown in Figure 1.

**Table 1. Distribution network generation and feeder reliability data**

Component	Failure rate (occ/year)	Repair time (hours)	Switching time (minutes)	Stuck probability
Substation A, B or 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 or 2	0.12	4.0	60.0	
Section 3 or 6	0.06	4.0	60.0	
Section 4 or 5	0.04	4.0	60.0	
Section 7	0.08	4.0	60.0	
Third feeder	0.32	4.0	60.0	
Breaker A, B or C	0.0036	12.0	60.0	0.01

**5.2 Equivalent Distributed Generation Reinforcement Alternative**

In order to compute the amount of distributed generation capacity providing the reliability enhancement identical to that of the 13 kV feeder, a range of capacities from 1 MW to 6 MW are considered in the studies. The computed different load points frequency and duration values as well as the overall system Expected Energy Not Supplied (EENS) figures for various options considered in this study are shown in Table 2, 3 and 4. Adding a third feeder or a DG has improved the overall feeder reliability. The improvement in load point (customer) indices is dependent on the selected option as seen from frequency and duration results shown in Table 2 and 3. If the objective is to improve indices for a set of customers, then

it is important to focus on individual load point indices in selecting the most optimal alternative.

In this study, the main focus is to improve the overall feeder reliability. The reliability index chosen for sizing an equivalent generator(s) is EENS. It is expressed in kWh per year. EENS is calculated based on the frequency, duration and the amount of load interruptions. The computed EENS indices for the existing configuration, the distribution reinforcement and different distributed generation reinforcements are summarized in Table 4.

The EENS results presented in Table 4 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 DG 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 much difference to reliability, but in real life it is important to include location of the unit in comparing various options.

**Table 2. Frequency of Interruptions per year for existing configuration, third feeder addition and distributed generation reinforcements for the distribution network considered**

Load ID	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"
Load A	0.55886	0.40967	0.42912	0.41714	0.40917	0.40945	0.40945
Load B	0.55886	0.40967	0.42912	0.41714	0.40917	0.40945	0.40945
Load C	0.55886	0.18985	0.21873	0.21873	0.18961	0.18975	0.18975
Load D	0.55886	0.18985	0.18961	0.18961	0.18961	0.08021	0.18975
Load E	0.71854	0.56954	0.62861	0.60861	0.56940	0.56924	0.51722
Load F	0.71854	0.56954	0.67857	0.62861	0.56940	0.56924	0.56924
Load G	0.71854	0.56954	0.67857	0.62857	0.56940	0.56924	0.56924

**Table 3. Duration of Interruptions (hours per year) for existing configuration, third feeder addition and distributed generation reinforcements for the distribution network considered**

Load ID	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"
Load A	1.879	0.410	1.836	1.836	0.409	0.409	0.409
Load B	2.239	0.410	2.196	2.196	0.409	0.409	0.409
Load C	2.418	0.190	2.365	2.122	0.190	0.190	0.190
Load D	2.538	0.190	0.190	0.190	0.190	0.190	0.190
Load E	2.638	0.570	0.679	0.679	0.679	0.569	0.569
Load F	2.818	0.749	1.814	0.858	0.858	0.749	0.749
Load G	5.147	0.989	3.124	1.738	1.098	0.989	0.989

**Table 4. Expected Energy Not Supplied (EENS in kWh per year) for existing configuration, third feeder addition and distributed generation reinforcements for the distribution network considered**

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

The probabilistic method presented in the paper helps in identifying the best location for the units in the local area and in determining the output requirements of the distributed generator(s). The computation of the reliability based equivalent distributed generation capacity to replace a distribution reinforcement requirements will also 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 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 and the smaller units have the economic advantage of receiving distribution capital deferral credit by replacing distribution requirements.

## 6.0 CONCLUSIONS

The concepts and applications of a probabilistic reliability model for computing distributed generation 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 distributed generation 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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