Reliability-oriented Distribution System Expansion and DG Deployment Using a Dynamic Programming Based Method

Joydeep Mitra, Mallikarjuna R. Vallem
The Klipsch School of Electrical and Computer Engineering
New Mexico State University
Las Cruces, New Mexico 88003, USA

Abstract - With increasing penetration of distributed generation (DG) future power systems will be interconnected in a gridlike fashion for enhanced reliability. These grids, called 'microgrids,' will be expected to operate in both grid-connected and islanded modes. This paper presents a rational method of building microgrids optimized for cost and subject to reliability stipulations. A unified method is formulated, based on dynamic programming, to expand a distribution system into a microgrid that satisfies reliability guarantees. The expansion consists of adding suitable quantities of DG at suitable locations and increasing feeder capacities or adding new feeders, and is optimal in that the cost of expansion is minimized. The cost includes annualized capital cost of adding the DG and feeders, and annualized operation and maintenance. The matching of combined heat and power (CHP) to heat loads is also exploited within this method. The paper describes the formulation of this problem which is one of the non-linear optimization types and demonstrates the method on an 8-bus system.

Keywords - distributed energy resources, microgrid, reliability, reliability differentiated service, dynamic programming.

1 Introduction

IN recent years there has been a global movement in the direction of adoption and deployment of distributed and renewable resources. The factors driving this movement have been numerous and diverse, but perhaps the most significant have been (a) diminishing fossil fuel reserves, (b) pressure from environmentally conscious groups, (c) the avoidance of the time and cost of transmission and distribution (T&D) expansion, and (d) government subsidies. These factors have contributed to an increased use of distributed generation (DG) in modern distribution systems. As the penetration of DG increases within distribution systems, it is likely that these systems, which have traditionally been radially connected, will evolve into weakly meshed networks in order to realize the economic and reliability benefits of DG. These networks are referred to as *microgrids*.

Of all the benefits of microgrids, reliability is arguably one of the most compelling. It is a major consideration in cases where the cost per kW is an issue. Moreover, the ability to install DG at or near load points immediately opens up the opportunity to offer reliability-differentiated services. These considerations have motivated our attempts to develop methodologies for reliability-centered design and planning of systems where DG can be deployed. In recent times, increasing awareness of reliability issues have resulted in reliability being considered as an important factor in network planning [1]–[7].

System expansion has been addressed by many researchers before [8]–[12]. Some [8]–[10] have addressed the optimal placement of DG in the distribution network. Others [11], [12] have focused on utilization of combined heat and power (CHP) mode of DG to benefit a compact cluster of loads. Most of these approaches have attempted to preserve the fundamentally radial structure of the distribution system. However, we believe there should be an appropriate number of loops present in a microgrid to achieve higher reliabilities through alternative flow paths and greater flexibility in system reconfiguration. In this paper therefore our approach is directed toward the development of microgrids that are networked in structure and conform to the US Department of Energy's vision of microgrids that can operate in both grid-connected and islanded modes [20], [21].

The development of optimal microgrid architectures, as envisioned by the authors, consists of two aspects: (a) optimal sizing and siting of DG, and (b) optimal network topology, comprising an optimal set of interconnections and associated capacities. In both these aspects, the optimization seeks to determine the most economical architecture that meets stipulated reliability criteria. In prior work [16]–[19], the authors have solved these problems independently. This paper presents a unified method, based on dynamic programming, to expand a distribution system into a microgrid that satisfies system-wide and local reliability guarantees. The expansion consists of adding suitable quantities of DG at suitable locations and increasing feeder capacities or adding new feeders, and is optimal in that the cost of expansion is minimized. The matching of combined heat and power (CHP) to heat loads is also exploited within this method.

The penetration of DG will be driven partly by the distribution company, partly by consumers, and, possibly, partly by independent parties if there is a sufficient profit motive. While it is expected that individual consumers will largely install smaller units in a more dispersed manner, the distribution company, or a larger consumer, or a consortium of smaller consumers may decide to install larger units in strategic locations to deliver certain reliability guarantees at one or more locations. Our work targets this scenario. It takes the reliability guarantees into account and determines how much DG should be deployed, where, and what kind of network augmentations are required to accommodate them.

Our work uses Dynamic Programming (DP), which is an analytical optimization method that almost always yields an optimal solution. This method has been used before in transmission planning [13], [14] and distribution system planning [15]. The method presented in this paper is different from previous work in the sense that an explicit reliability criterion has been incorporated, using the reliability of the system as the state of the DP. This algorithm enables the problem to be decomposed into stages. These stages do not have any temporal bearing; instead they correspond to the stages of the DP, where each stage represents a collection of deployment configurations utilizing the same total number of unit links (defined in the next section) and generation units. Further, our DP formulation permits the separation of the microgrid into islands, where such separation benefits the reliability of the network. In some of our prior work [16], [17] we have used DP to optimize network augmentation. In this work we simultaneously optimize DG deployment and network augmentation.

2 System Modeling

Generators: These are modeled as two-state devices. Each generator i is described by its maximum generating capacity and its forced outage rate FOR_i.

A *unit* of DG has a unit peak electrical capacity and proportional heat capacity. The cost of a unit of DG can vary from one location to another. The number of units at a particular location constitutes the total peak capacity of the DG at that location. DG will have same dispatch and reliability characteristics as that of any other generators.

Load: For the purpose of system planning, the load has been assumed to remain constant at the coincident peak.

Feeders: The basic element of the distribution network is the unit-link which is a feeder with the following characteristics:

A *unit-link* connecting a pair of buses is a line of fixed capacity, and of length corresponding to the right of way between the buses. Unit-links between different bus pairs will have different lengths, impedances and costs, but same capacity. A feeder consists of a number of unit-links in parallel.

Network Model: A linearized network model in the form of DC Load Flow has been used in this work. This model is described later, in section 3.5

3 Problem Formulation

Consider a system with N_B nodes, N_G^{avail} generators initially in the system, and N_F feeders. The framework of this paper aims to augment the system with additional DG and feeder upgrades so as to achieve a reliability target. This augmentation can include resource addition in case of load growth in a distribution system. We consider installing a particular type of DG and also upgrade the interconnection capacity either by adding feeders through new rights of way (ROW) as well as the existing ones.

The energy demand is divided into heat demand and electrical demand. A unit resource is defined as a DG which has a unit power and heat capacity and has a fixed cost depending on the location of deployment.

The costs arising from the deployment strategy are modeled and a cost optimization is performed. These costs are the annual costs which arise from the system augmentation with additional DG and feeders. The different types of costs considered are capital costs, operation and maintenance costs, fuel costs and savings obtained from using the heat output of the DG for direct heating. These costs involved can be classified as deployment costs, fuel costs and heat compensation costs which will be detailed below.

3.1 Deployment Cost

Let the total candidate locations where DG can be deployed be N_{Gen} and candidate transmission ROW be N_{Trans}. An N_{Gen} vector of deployment cost 'J_1' is developed such that its ith element is the cost of deploying a unit of DG at the ith candidate location. An N_{Trans} cost vector 'J_2' is developed such that its ith element is the cost of adding a unit link at the ith ROW. The solution vector 'F_1' is an N_{Gen} dimensional vector that indicates the number of units of DG that should be deployed at different candidate locations. The N_{Trans} dimensional integer vector 'F_2' indicates the number of unit links that should be deployed on candidate ROW. A linear depreciation is assumed where annual depreciation rate will be r. Then the cost for system upgrade is

$$Q_1 = r(J_1^T \cdot F_1 + J_2^T \cdot F_2) \tag{1}$$

where

r = rate of depreciation per year
F_1 = N_{Gen} dimensional solution vector where the ith entry is number of units of DG at ith candidate location
J_1 = N_{Gen} dimensional vector of generation deployment costs.
F_2 = N_{Trans} dimensional solution vector where the ith entry is number of unit links on ith ROW
J_2 = N_{Trans} dimensional vector of feeder deployment costs.

3.2 Heat Compensation Cost

If the heat demand at any node is not supplied by the CHP at that node, excess heat demand is compensated by gas heating. So there is an excess cost for gas required to supply the additional heat demand which is proportional to the heat curtailment. The heat curtailment is given by a vector C_H of dimension N_B:

$$C_H = (H - G^{new} \cdot u_h)^+ \tag{2}$$

where

H = N_B dimensional vector of heat demand at the nodes

u_h = heat output of a unit of DG
G^{new} = N_B dimensional vector of total DG capacity at the buses.

The value of u_h can be zero if the type of DG considered has no heat output making the model more generic. In (1), the superscript '+' denotes the following. If this operation is performed on a vector A, then in the resulting vector A^+ the elements are modified as

$$a_i^+ = \begin{cases} a_i & \text{if } a \geq 0 \\ 0 & \text{if } a < 0 \end{cases}$$

For simplicity we take the units for heat as power units. The additional costs for the heat compensation will be

$$Q_2 = j_{gas}(U_N \cdot C_H)8760 \tag{3}$$

where

U_N = unit vector of dimension N_B
j_{gas} = cost of gas to produce a unit of heat.

3.3 *Fuel Cost*

The cost of fuel consumption per year will be

$$Q_3 = \sum_{i=1}^{8760} \sum_{j=1}^{N_B} D_{ij} \tag{4}$$

where D_{ij} is the load at bus j during hour i.

Cost Q_3 is independent of the size of deployment at the buses and is dependent only on the total energy consumed over the year. For this reason, it is not necessary to consider this term in optimizing the deployment strategy, and it is acceptable to omit Q_3 from the objective function.

3.4 *Optimization Problem*

Having omitted the fuel cost from the objective function, we can now express the problem as follows.

$$\text{Min } \ Q = Q_1 + Q_2 \tag{5}$$

Subject to:

$$EIR \geq R_0$$

where

EIR = Energy Index of Reliability
R_0 = minimum reliability desired.

The reliability constraint specifies a target reliability the system is required to meet. Computation of energy index of reliability is explained in the following section.

3.5 *Reliability Evaluation*

Network and generation constraints affect the availability of power at every bus in the system. In this work, a linearized representation is used to model the power flows in the system. This representation is considered appropriate in this method because of the following reasons.

1. For a planning study involving DG, which typically has inadequate VAr capability, it makes sense to plan for real power generation first and then for VAr support. DC flow is more appropriate when dealing with only real power flows, particularly since there is inadequate information about reactive power.

2. In this work it is assumed that the DG will be installed at buses on three-phase primary feeders, so unbalance is not a concern.

The DC load flow model [22] is applied in the following form.

$$\text{Min } \ C_T = \left(\sum_{i=1}^{N_{bus}} C_i \right)$$

Subject to:

$$\begin{array}{rcl} \hat{B}\theta + G + C & = & D_{peak} \\ G & \leq & G_{max} \\ C & \leq & D_{peak} \\ \left| b\hat{A}\theta \right| & \leq & F_{max} \\ \theta & & \text{unrestricted} \end{array} \tag{6}$$

where

D_{peak} = N_B dimensional vector of bus load
C = N_B dimensional vector of bus curtailments
C_T = total system load curtailment
G_{max} = N_B dimensional vector of available generation at the buses
F_{max} = N_F dimensional vector of flow capacities of feeders
b = $N_T \times N_T$ primitive (diagonal) matrix of feeder susceptances
$\hat{A}$ = $N_T \times N_B$ element-node incidence matrix
$\hat{B}$ = $N_B \times N_B$ augmented node susceptance matrix $= \hat{A}^T b \hat{A}$
θ = N_B vector of bus voltage angles.

This model is considered under the assumption that dispatch is possible to achieve minimum curtailment in the system. *EIR* is calculated by

$$EPNS = \sum_{k=1}^{N_C} C_{Tk} \times P_{Ck} \tag{7}$$

$$EIR = 1 - \frac{EPNS}{D_{tot}} \tag{8}$$

where

C_{Tk} = minimum system curtailment for kth contingency
P_{Ck} = probability of kth contingency
N_C = number of contingencies
EPNS = expected power not served
D_{tot} = total power demand.

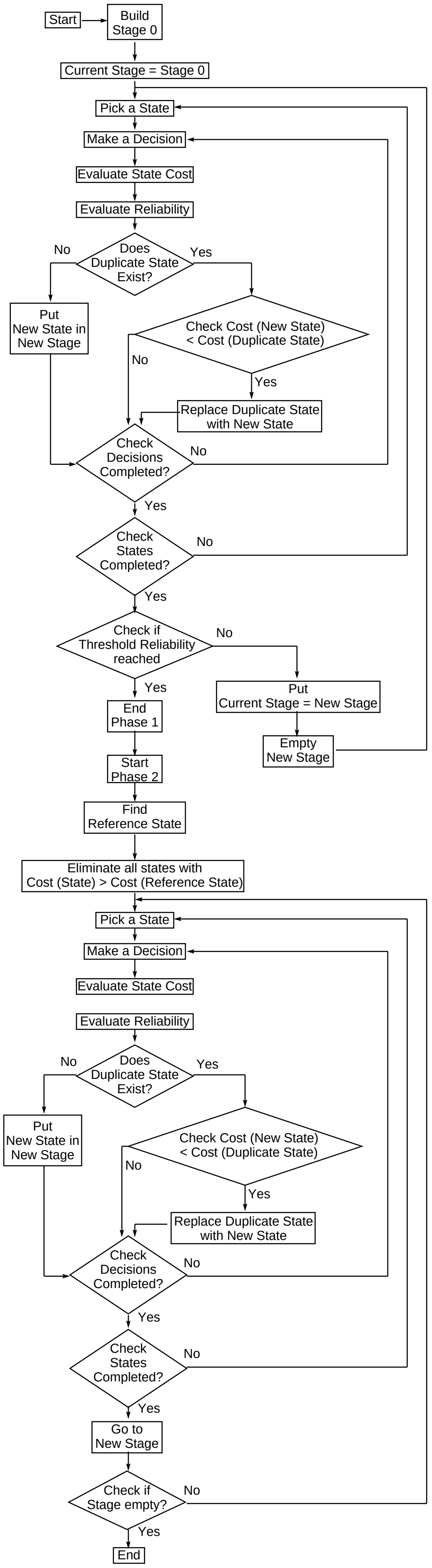

Figure 1: The dynamic programming algorithm.

In evaluating the reliability of each configuration, the set of components that constitute the configuration are taken into account, and from this set all contingencies, up to second order generation contingencies and first order transmission contingencies are considered. The feasible dispatch (6) is determined for each contingency, and the *EPNS* of the configuration is determined by applying (7) over all these contingencies. For the system examined here, the contingency set described above spanned a large enough part of the probability space. For other systems, higher order contingencies may be considered if necessary.

4 Solution Strategy

The problem is solved in a stage-wise fashion where at each stage the system is incremented by either a unit-link or a unit DG. In the following subsections, first the various structures of the DP are described, and then the strategy is explained. The algorithm is shown in Figure 1.

4.1 The Dynamic Programming Algorithm

DP Stage: Each stage is represented by the total number of units of both DG and unit links that have been added to the system so far. This means that stage S_k of the DP has utilized k units to upgrade the system. These k units can be distributed either as units of DG or unit links among the possible rights of way in different ways, giving rise to different system configurations. In light of the objective function, all configurations in stage S_k will be such that

$$\sum_{i=1}^{N_{Gen}} F_1^i + \sum_{j=1}^{N_{Trans}} F_2^j = k \qquad (9)$$

DP State: Each configuration mentioned above has an associated cost. Also, each configuration provides us with a measure of system-wide reliability index for each critical location. This reliability measure serves as the state of the DP.

DP Decisions: As mentioned earlier, consecutive stages of the DP are built by adding more and more units. Each possible unit that can be added to the system is an alternative. These are defined as the "decisions" of the DP. This scheme of adding units in the system gives the capacity of both the DG and transmission in the optimal topology.

It is possible that in a given stage, different configurations may have the same state, though with different costs. In other words, they might have the same value of the global reliability index, *EIR*. Therefore, during the building of stages, it is very important to check for such states. Whenever a new state for the next stage is generated by testing a decision, a check is performed to see if any other state having the same *EIR* exists. If such a state exists and has a higher cost, then it is replaced with the less expensive state. In other words we have replaced the path leading to a system state by another path having a lower cost that leads to that same system state. This ensures that the configuration represented by a state in a given stage is the most optimal way of achieving the reliability it offers by adding as many unit-links as represented in the stage.

Treatment of the State Space: The reliability of the system is used as the state of the DP. Therefore, the number of possible states of the DP is very large, only limited by the precision of the indices used. But reliability indices in power systems are typically computed to a finite precision. As a result, the maximum number of states becomes finite, and the DP becomes discrete. All network configurations with same reliability index, to a given precision, are treated as configurations that offer the same reliability. In this work, for the sake of demonstration, reliability indices were computed to four decimal places.

4.2 Algorithm

This problem is solved in two phases, as described below.

Identification of feasible solution: The DP is solved in phases. Phase I starts building new stages and evaluating different decisions till the reliability of at least one solution in the current stage reaches the stipulated reliability criterion. Then the phase I ends and we have one initial feasible solution which forms the reference for phase II.

Identification of optimal solution: In phase II all the states which have cost greater than the reference state are eliminated. The remaining states are used to build subsequent stages. Whenever a decision ends up reaching a state which has the system cost greater than the reference cost, that trajectory ends. Whenever we encounter a state that satisfies all the optimization constraints and has a cost lower than the reference state, that state is taken as the reference state. Phase II ends when all the trajectories have ended up with a higher cost than the reference cost. The final reference state determines the optimal solution for the problem. The optimal solution specifies a combination of the number of DG units to be deployed at each candidate location as well as the number of unit links to be installed along each of the feeders to achieve the reliability target at minimum cost.

5 Demonstration

The dynamic programming algorithm is demonstrated on an 8-bus test system.

5.1 System Description

The test system is a radial standalone system and islanded operation is considered. There are five load buses with a coincident peak electrical load of 6 MW and heat load of 10.236 MBTU/hr. A generator with a capacity of 3 MW is available at bus 7. The test system is shown in Figure 2.

For the purpose of demonstration the capacity of each unit link as well as a unit DG is taken to be 0.1 MW. A unit of DG is considered to have a peak heat output of 0.3412 MBTU/hr. The cost of deploying a unit of DG is taken as 50000 $ on an average at the buses. The cost of a unit link between the nodes is taken to be proportional to the length of the line with an average of 60000 $ per unit link per mile. Gas heating is considered available if direct heat from the DGs is not sufficient to support the heat loads. The cost of gas is taken as 8 cents/kWhr.

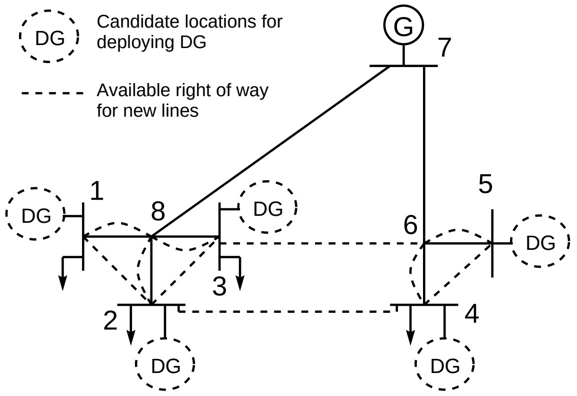

Figure 2: Eight-bus test system.

Tables 1 and 2 provide the network and load information. As shown in the Table 1, five new rights of way are identified where new feeders can be installed. Some existing feeders are also chosen as candidate upgrade options.

Start bus	End bus	Length (Miles)	Capacity (MW)
1	8	1.0	0.5
2	8	0.75	0.5
3	8	1.0	1.2
8	7	2.3184	2.2
6	7	1.75	1.85
4	6	1.25	0.9
5	6	1.25	0.95
3	6	2.16	New ROW
2	4	2.64	New ROW
1	2	1.25	New ROW
2	3	1.25	New ROW
4	5	1.56	New ROW

Table 1: Network data for the 8-bus system.

Bus	Electrical load (MW)	heat load (MBTU/hr)
1	0.75	2.559
2	0.75	2.559
3	1.8	6.14
4	1.3	4.4356
5	1.37	4.674

Table 2: Load data.

5.2 Results

A reliability target of $EIR \geq 0.96$ is used. The results obtained from applying the optimization method to the test system are shown in Tables 3 and 5. The final system layout is shown in Figure 3.

The CHP benefits of DG can be best exploited when deployed near the load centers. The heat compensation costs try to restrict the DG capacity to that required to support the heat loads but the difference in deployment costs tends to place DG more at locations of lower cost.

Bus	DG capacity (MW)	Bus	DG capacity (MW)
1	0.6	4	0.5
2	0.4	5	1.4
3	1.1		

Table 3: Results: optimal DG augmentation plan.

Start Bus	End bus	New feeder capacity (MW)
4	6	0.3
3	6	0.3
2	4	0.1
4	5	0.1

Table 4: Results: optimal feeder augmentation plan.

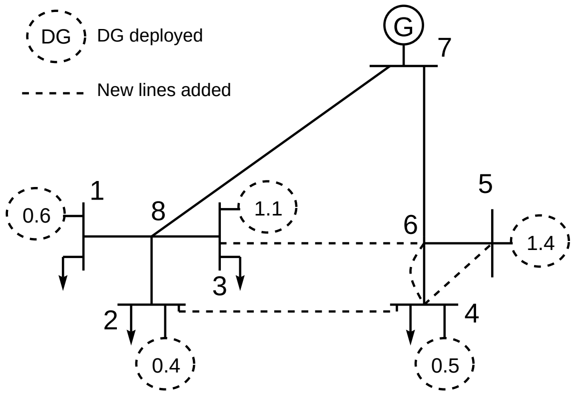

Figure 3: Microgrid with optimal deployment

The feeders closer to bus 7 have higher capacity than those at the terminal buses as would be expected in a radial system. DG are generally located close to the load centers for maximum benefits. This will cause power to flow in the reverse direction away from terminal buses. Hence the capacity of the feeders closer to the terminal nodes is strengthened in the optimization. Though the length of the feeder connecting bus 3 and 6 is longer which means higher cost, the reliability benefit offered by loop closing dominates the cost in the optimization. Loop closing feeders are however less which would be expected as the test system looks radial. Further an engineering decision can be made to see if the results obtained by the method can be made more simple. For example, if the optimization determines only one unit link along many new rights of way, it could be decided if such a solution is practically viable and appropriate action can be taken.

6 Conclusion

This paper presented a rational approach to designing cost optimized microgrid architectures that are subject to system wide and locational relibility stipulations.

The approach consisted of applying dynamic programming to determine the optimal upgrade strategy with DG deployment and network upgrade. A scheme was implemented to render the size of the problem manageable and to minimize the storage requirements. The formulation presented is practical and flexible, being capable of accepting an arbitrary number of locational reliability guarantees in addition to a system-wide reliability specification. The implementation, too, is pragmatic, and considers a realistic set of component contingencies.

It is expected that this method will provide a more rational approach to enabling the evolution of a distribution network than ad hoc expansion in response to load growth. The method presented is likely to be suitable for dense urban areas. While this method is equally applicable in rural areas or otherwise sparsely connected distribution systems, it is likely that similar results may be obtained by simpler methods. Further work on this project is in progress, and will be reported in due course.

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7 Biographies

Joydeep Mitra recieved his B.Tech. from Indian Institute of Technology, Kharagpur, and his Ph.D. from Texas A&M University, College Station. He is currently Associate Professor of Electrical Engineering and Associate Director of the Electric Utility Management Program at New Mexico State University, Las Cruces. Dr. Mitra is a Senior Member of the IEEE, and recipient of an NSF Career Award. His research interests include power system reliability, distributed energy resources, and power system planning. (email: jmitra@nmsu.edu)

Mallikarjuna R. Vallem received his B.Tech. (Hons.) from Indian Institute of Technology, Kharagpur. He is currently pursuing a doctoral degree in EE at New Mexico State University. His research interests are in the area of power system reliability, Distributed resources and deployment optimization. (e-mail: mallikv@nmsu.edu)