Placement of Dispersed Generations Systems for Reduced Losses

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Abstract

Recent improvements in fuel cell technology along with an increasing demand for small generator units have led to renewed interest in dispersed generation units. This work demonstrates a methodology for deploying dispersed fuel cell generators throughout a power system to allow for more efficient operation. A detailed study of the system losses and sensitivities on Eastern Washington system as part of the larger WSCC system has been completed. This work presents an algorithm to determine the near optimal, with respect to system losses, placement of these units on the power grid. Further, the impacts of dispersed generation at the distribution level are performed with an emphasis on resistive losses, and capacity savings. The results show the importance of placement for minimizing losses and maximizing capacity savings.

1. Introduction

Dispersed, or distributed, generation (DG) will affect the electric power system at the system and, more directly, at the distribution level. This study investigates transmission and distribution losses based on location. Simulations will show that proper placement of the units will reduce losses normally seen by the system while improper placement may actually increase system losses. Proper placement will also free available capacity for transmission of power and reduce equipment stress. Moreover, cost savings can be expected by deferring transmission and distribution upgrades. Specifically, this work investigates the losses seen on the Eastern Washington system and the practicality of dispersed generation to reduce these losses. An approach is developed to systematically locate plants on a system wide basis and along select feeders. Using the developed methodology the locations of plants along several feeders is suggested.

2. Background

For most of the history of electric power systems, generation has been derived from large central-station plants due to economies-of-scale. Fossil-fuel plants have comprised the majority of this power generation. Traditionally, there was strong yearly demand growth, which was stable at around 6-7%. Environmental issues and the oil crisis began to pose new problems for the power industry in the 1970s. By the 1980s, these factors and changes in the economy had led to much smaller demand growth of around 1.6% to 3% [1]. At the same time, transmission and distribution (T&D) costs has grown from a historical level of 25% to around 150% of generation costs. T&D costs now represent almost two-thirds of the capital expenditure budget for the utility industry. Thus, as a result of reduced demand growth, increased T&D cost, heightened environmental concerns, and various regulatory and technological changes, large central-station plants are often impractical. The utility industry's generation paradigm is shifting from economies-of-scale to something that has been coined economies-of-mass production [2].

DG is considered here to be any modular generation located at or near the load center. It can be applied regionally in the form of renewables, such as, mini-hydro, solar, wind, and photovoltaic systems (though each of these are restricted by geographic requirements) or in the form of fuel-based systems, such as, fuel cells and microturbines. By integrating DG into the utility's power grid, line upgrades can be postponed, and there exists the possibility of greater efficiency of power delivery. Power flows should be reduced, and thus, losses minimized. In particular, heavily loaded feeders or transmission corridors can be relieved. It may also be an opportunity to improve power quality allowing customers and utility equipment more years of usage [1,3,4].

A general goal of utilities is to increase overall efficiency from fuel to power delivery. Ideally, any new source of generation should increase the overall

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generation efficiency. Conventional thermal generating power plants exhibit a maximum efficiency of 33-35%. Combined cycle and fuel cell units have achieved electrical efficiencies greater than 42%; and some of the latest fuel cell technologies just within reach of commercialization are yielding upwards of 55-60% electrical efficiency [5]. Because of the high temperatures achieved by the combined cycle and some of the generation fuel cell technologies, combined heat and power output will allow the overall thermal efficiency to approach 85% for certain applications [6-8]. Among the fuel cells, electrical efficiencies for phosphoric-acid fuel cells have been as high as 43%, molten carbonate fuel cells as high as 52% and solid-oxide fuel cells 51% [3,7].

The most cost competitive generation technology in recent years has been combined cycle units. Still, small DG has the potential to compete with combined cycle to serve a significant percentage of the new load (predicted to be around 200,000 megawatts of new load by 2010 [9]). Particularly, if, as is quite likely, most of the load growth is not as dense as the new load patterns of the mid 1900s, but rather scattered sporadically throughout different regions. DG may be the most appropriate approach to serve a large share of this growth.

Small gas-turbine technology, or microturbines, is also proving to be a competitive form of DG. In late 1998, microturbines went to commercialization with a broad range of support from utilities, IPPs, and commercial/small industrial customers. Although this method of electricity production is similar to conventional, the modular size of microturbines make them efficient enough to compete with fuel cells, and cost-effective enough to compete with the large central generation [10]. The power rating of this technology typically ranges from 50 kW to 250 kW. They can operate from various fuels including natural gas, diesel, gasoline, ethanol, propane alcohol and JP. The cogeneration opportunities in supplying heating, absorption cooling, and industrial processing are important considerations in terms of cost effectiveness. So while electrical efficiency is near 30%, the high heat rating allows for the overall combined heat and power to reach 85% efficiency. Similar to the fuel cells, these systems can be located practically anywhere. Further, the sulfur dioxide and nitrogen oxide emissions are at very low levels since microturbines use gas fuels. Noise levels have been demonstrated to be as low as 30dB at 30 feet for a 50 kW unit. A 250 kW unit uses a space of 13 square feet standing 3 feet high.

3. Transmission system losses

In this section, a method for placement of dispersed generation units to optimize power exports is proposed. The method minimizes system losses during periods of high power transfer. The problem is representative of one experienced in the inland Pacific Northwest during the summer period, when large amounts of power are sent to Western Washington, Nevada, and California (from now on referred to as the West). Between May and September, the Northwest experiences relatively light loads since the summers are not humid and the nights are very cool. Furthermore, the weather is often windy, thereby, providing natural cooling of transformers and conductors. This light loading and natural cooling leads to excess capacity on the system, which is utilized by selling power to the West. The Northwest sees high system losses at these times due to transfers over long distances. Finally, it is worth noting that the system under study is almost completely hydro (approximately 95%) and runs all units base-loaded, selling any excess to neighboring systems. The only time the units are intentionally shutdown is for regular maintenance.

3.1 Calculation of losses

Electric power systems designed with generating units that are widely scattered and interconnected by long transmission lines may suffer significant losses [11]. The losses depend on the line resistance and currents and are usually referred to as thermal losses. While the line resistances are fixed, the currents are a complex function of the system topology and the location of generation and load.

Consider the well-known power flow equations, with complex power $S_i = P_i + jQ_i$, injected at bus i as

$$P_i = V_i \sum_{j=1}^{n} Y_{ij} V_j \cos(\delta_i - \delta_j - \gamma_{ij}) \tag{1}$$

$$Q_i = V_i \sum_{j=1}^{n} Y_{ij} V_j \sin(\delta_i - \delta_j - \gamma_{ij}) \tag{2}$$

where Y_{ij} is the magnitude of the i-j^{th} element of the bus admittance matrix, V_i is the voltage magnitude at the i^{th} bus, γ_{ij} is the angle of the i-j^{th} element of the bus admittance matrix, and δ_i is the phase angle of the voltage V_i.

In this work, only the real power injections as they relate to transmission losses are of concern. As a result, algorithms for voltage scheduling to reduce losses are not addressed. The system losses can be expressed as

$$P_L = \sum_{i=1}^{n} P_{G_i} - \sum_{i=1}^{n} P_{D_i} \tag{3}$$

where P_L is the real power loss, P_{Gi} is the real power generated at the i^{th} bus, P_{Di} is the real power required at the i^{th} bus. The losses in (3) may be difficult to evaluate analytically. Alternatively, an established method using the B-loss coefficients, based on an approximation for the line losses, is commonly employed by the power utility industry [11]. The losses are expressed as a quadratic function, near some base case, of the generator bus powers. This is expressed as

$$P_L = \sum_{i=1}^{n} \sum_{j=1}^{n} P_i B_{ij} P_j + \sum_{i=1}^{n} P_i B_{i0} + B_{00} \quad (4)$$

where P_i is the real power at the i^{th} bus, B_{ij} is the *nxn* matrix of quadratic loss coefficients, B_{i0} is the dimensionless vector of linear loss coefficients, and B_{00} is the constant loss coefficient. This can be written in a general matrix expression as

$$P_L = P^T[B]P \quad (5)$$

B is a square symmetric matrix dependent on the base-case load flow (specifically, voltage profile, distribution of load, and the complex power at each generator bus; the development is widely available and not reproduced here [12]). The coefficients are found by linearizing the power flow equations around the operating point. Thus, (5) is exact only for the specific load and operating conditions for which the loss coefficients are derived. *B* is generally considered reasonably constant for small generator bus power variations as long as the load bus voltages and plants maintain constant magnitudes and plant power factors. Thus, if wide shifts in load are not under study and average operating conditions are generally present, then reasonably accurate real power losses can be calculated from *B*. Note, the coefficients are normally only calculated at the generator buses, which poses difficulties for the present problem as units may be located at any bus in the network.

If the above conditions do hold, then it may be useful to recalculate *B* including possible locations of dispersed units and then simply select locations for DG units based on the loss sensitivities. Given here as

$$\frac{\partial P_L}{\partial P_i} = 2B_{ii}P_i + \sum_{\substack{j=1 \\ j\neq i}}^{n} B_{ij}P_j + B_{i0} \quad (6)$$

For the proposed problem, only power injections at load buses would be of concern. Generator outputs would be fixed and any decrease in loads will be exported. These factors are taken into consideration when solving for the coefficients. This procedure has been demonstrated on a simple four-bus system [13] (which we omit for brevity). This development shows that a change in generation at one or more buses, specifically, the addition of generation at a load bus will affect the real power losses and their loss sensitivities to generator outputs. The variations will occur either via sign or magnitude or both. Hence, proper placement of the dispersed generating units may reduce system losses; however, some placements can cause power losses to increase. Also, note the loss coefficients tend to be inaccurate for large load changes.

3.2 Placement methodology

In order to determine the best placement of the units for the study system, an algorithm was created that would be appropriate given the particular constraints on operations. Since the bulk of the generation is hydro, the generation units are run base-loaded with excess available for sales. Therefore, unit commitment and economic dispatch are not appropriate for this system. Extant software did not allow for calculation of the loss coefficients at all the desired buses. Further as noted in the previous, the accuracy of the *B* matrix approach is probably unsatisfactory for the problem of this study.

Using the load data collected during 1994-95, the algorithm was applied to determine the best placement of new distributed units in order to maximize power available for sale and minimize losses on the system for a given load. This data was analyzed using the Power Technologies, Inc., (PTI) Power System Simulation for Engineering (PSS/E) Software Package. The approach was to run a base case to yield initial conditions of the system. From this run, *80.21* MW of losses were calculated for the summer peak, and *46* MW of losses were found for the winter peak.

The algorithm proceeds as follows:

1. Perform power flow calculations to determine initial conditions of the system during peak load.
2. Select possible locations of units based on areas that have large losses.
3. For each selected location, recalculate system losses if 10MW of generation are added.
4. Rank each location according to system losses.
5. Based on the priority in step 4, incrementally add units until losses are seen to increase or total amount of desired new generation is placed.
6. Repeat for winter periods for comparison. (Note, since load is heavier during the winter periods, loss reduction will be minimal.)

3.3 Numerical Results

A typical output of the winter power flow using PSS/E is given in Table 1. After all the selected locations have been simulated via the power flow process, they are ranked. These rankings are given in Table 2 showing the best and worst locations for the summer transfer peak period. It is important to note that the worst location adds 0.7 MW of losses or an effective decrease of 7.1% in new generation added. This arises primarily due to increased flows on the 115kV system. In contrast, the best location decreases losses by 0.23 MW or an effective increase of 2.3%. Thus, from best to worst, we see a nearly 10% difference in added capacity. Table 3 shows the resulting losses as multiple units are added incrementally. The incremental addition of capacity is continued until the original value of losses is reached again. In this case, approximately 90 MW could be added to the system without increased loss and so is fully available for sale to neighboring utilities.

Table 1. Power flow summary data for summer flows

SYSTEM SWING BUS SUMMARY						
BUS	**NAME**	**AREA**	**ZONE**	**MW**	**MVAR**	**MVAbase**
26321	PTS7SW NG20.0	26	260	393.7	242.8	835.0
AREA SLACK BUS SUMMARY						
AREA	**SWING**	**NAME**	**ZONE**	**MW**	**MVAR**	**MVAbase**
20 [northwest]	20557	CENTR G	200[ND]	261.7	280.0	811.0
			ACTUAL (MW)	**(MVAR)**	**NOMINAL (MW)**	**(MVAR)**
From Generation			1168.1	207.7	1168.1	207.7
To constant Power Load			600.0	179.7	600.0	179.7
To Bus Shunt			0	-178.4	0	-177.4
To Line Shunt			0	0	0	0
From Line Charging			0	261.3	0	254.2
VOLTAGE		**LOSSES**		**LINE SHUNTS**		**Charging**
Level	**Branches**	**MW**	**MVAR**	**MW**	**MVAR**	**MVAR**
230.0	19	47.83	425.09	0	0	151.2
115.0	228	28.81	92.81	0	0	110.0
60.0	3	.06	1.84	0	0	.1
34.5	9	.01	.36	0	0	0
30.0	3	.00	.74	0	0	0
23.0	1	.00	.35	0	0	0
14.4	3	2.14	74.30	0	0	0
13.8	20	.78	45.54	0	0	0
13.0	2	.00	.02	0	0	0
12.0	24	.40	9.03	0	0	0
4.2	3	.06	.89	0	0	0
4.0	6	.23	5.64	0	0	0
2.4	3	.00	1.34	0	0	0
TOTAL	324	80.32	657.94	0	0	261.3

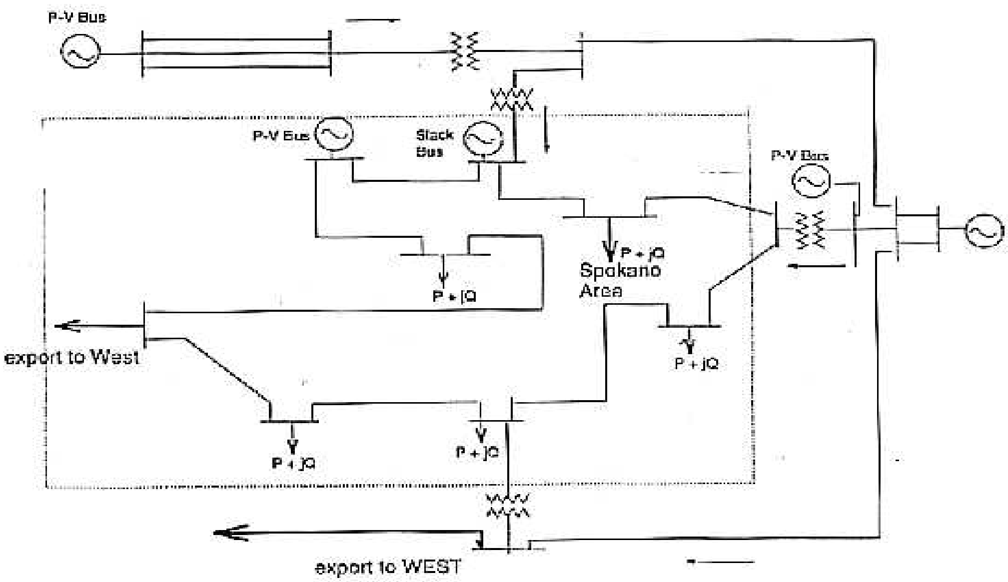

Figure 1. Flows in summer transfer period

Table 2. Results of system losses for 10 MW unit placement at select buses

Bus #	230KV	115KV	System	Ranking
Best locations				
20331	47.67	28.34	79.98	1
77	47.82	28.49	80.00	2
20273	47.80	28.51	80.01	3
91	47.82	28.51	80.02	4
510	47.72	28.35	80.04	5
20167	47.86	28.53	80.08	6
20954	47.75	28.44	80.16	7
179	47.83	28.64	80.16	7
21171	47.83	28.64	80.16	7
70	47.84	28.69	80.22	10
115	47.79	28.50	80.26	11
20652	47.77	28.51	80.26	11
40	47.87	28.70	80.27	13
10	47.81	28.51	80.29	14
312	47.82	28.52	80.31	15
20780	47.92	28.70	80.31	15
Worst locations				
148	48.05	29.00	80.75	36
106	48.04	29.05	80.79	37
531	48.01	28.92	80.84	38
21662	47.85	29.34	80.88	39
20142	47.84	29.38	80.91	40

Table 3. Results of system losses for placement on multiple buses

Iteration	Added Generation (MW)	230kV	115 kV	System
1	20	47.69	28.21	79.87
2	30	47.70	28.09	79.76
3	40	47.72	27.98	79.66
4	50	47.78	27.85	79.60
5	60	47.84	27.78	79.43
6	70	47.97	28.03	79.98
7	80	48.01	28.08	80.07
8	90	48.25	28.13	80.36
9	100	48.32	28.21	80.50
10	90 (Select units)	-----	--------	80.11
11	80 (Select units)	-----	--------	80.01
12	70 (Select units)	-----	--------	79.71

4. Distribution system analysis

The substation and feeder in a distribution system can be relieved of thermal loading stresses by correct placement of units but depends greatly on the location of loads on the feeder. This section addresses placement of the DG units on a selected feeder to obtain the greatest reduction in losses based on simulations of the distribution system.

To truly minimize losses, one should integrate over the entire load profile. This is much more important on the distribution system where there may be great daily or seasonal fluctuations of load on a particular feeder. Here, the authors suggest that the peak should be more heavily weighted as this will also correlate with capacity savings. Further, for the objectives of this study, it more clearly identifies the variation in loss reduction. As a result, placement is based on losses at peak load only.

4.1 Background - DG benefits to the utility

At the system level, reliability and power quality concerns are negligible for the penetration of DG investigated here and also, because there is no direct impact upon the customer. At the distribution voltage levels, the aggregate of benefits has to be considered more carefully. Local planning has to be integrated with generation and transmission planning. Optimal placement can be realized only by considering all factors, including the loss reduction achieved system wide, loss savings on the feeder and the ability to forego capacity upgrades. Less directly, benefits may also involve reduced use of fossil fuels, lower emissions of toxic gases, and lower capital investment risks due to under utilized capacity. In reference to specific transmission and distribution upgrades, costs arise from additional voltage supports required for the adequate transfer of power, reconductoring, acquiring new right-of-ways, new feeders and supporting substation equipment, and upgrades in substation transformers. Planning should weigh all the aforementioned factors against the cost of adding the dispersed units. Still, the purpose of this study is to identify impacts on the system losses and suggest siting methods rather than perform a detailed cost benefit analysis.

Each service area of a distribution system is limited by the thermal capacity and voltage-drop. In general, customer loads may be distributed along the feeder in many ways, and may be uniform, uniformly increasing, lumped or some other non-uniform pattern [14]. Load is often served by substations with feeders spanning out in different directions so that the far ends of the feeder may be serving a larger geographic area and greater load (see Figure 2).

DG applications may be especially useful in rural areas where long spans of primaries are constructed to serve loads sporadically located. These loads are generally referred to as low-load density areas. Low load density areas have limitations on the operation of the circuit ties due to the large distances between substations. Those tie lines must be available in order to provide the emergency service to the system should the source of supply be discontinued. Moreover, the ability to transfer load between substations may become significantly reduced

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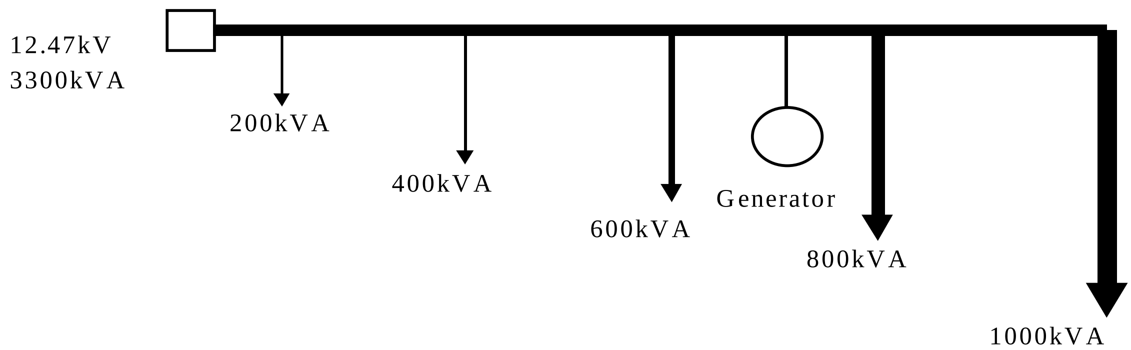

Figure 2. Example feeder with uniformly increasing distributed loads

unless the utility is willing to allow increased outage time as a tradeoff. Typically, the capacity in low-load density areas is limited by voltage-drop [14]. High-load density areas do not have as many restrictions with regard to load-transfer capability and service continuity. Most of the adjacent substations are configured appropriately to provide adequate support. Sufficient circuit ties are available to support the loss of a large transformer within the substation or the loss of main feeders. So typically, thermal limitations are more of a concern than voltage drop.

4.2 Placement on standard load distributions

Although it is obviously unrealistic, it is often instructive to analyze continuous load distributions. The following performs such an analysis on two common load distributions. Let the incremental losses over a differential line section at some point be given as

$$dP_{\mathrm{DL}}(x)\,dx = I^2(x)R\,dx \tag{7}$$

where *I(x)* is the current at location *x* with *x* measured from the end of the feeder, *R* is a per unit distance resistance and we use P_{DL} to emphasize these are the distribution losses only. The current distribution is proportional to the distribution of the demand if we assume constant voltage. Then we can find the total losses by integrating over the line of length *l* as

$$P_{DL} = \int_0^l I^2(x)R\,dx \tag{8}$$

Considering first the uniformly distributed load, as shown for example in Figure 3, *I(x)* increases linearly so with no DG placement

$$P_{\mathrm{DL}}^{\mathrm{U}} = I_0^2 R \int_0^l x^2\,dx = I_0^2 R\, l^3 / 3 \tag{9}$$

where I_o is the load current per unit length. Assuming that only one unit will be placed on this particular feeder with current output *I*, at say, location y, then

$$\begin{aligned} P_{\mathrm{DL}}^{\mathrm{U}} &= R\left(I_0^2 \int_0^l x^2\,dx - 2II_0 \int_y^l x\,dx + I^2 \int_y^l dx \right) \\ &= I_0^2 R\, l^3/3 - II_0 R(l^2 - y^2) + I^2 R(l - y) \end{aligned} \tag{10}$$

Differentiating with respect to *y* and setting the result

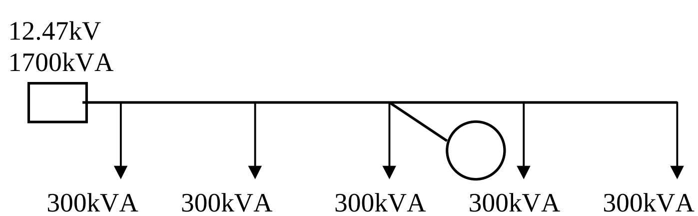

Figure 3. Example feeder with uniformly distributed loads

to zero, gives the optimal placement of the unit (assuming that I does not exceed the total load) to be

$$y = \frac{I}{2I_0} \tag{11}$$

So if the DG unit supplies all the load (i.e., $I=I_0 l$) then the unit should be placed at the halfway point (as in Figure 4) with a loss reduction to $I_0^2 R l^3 / 12$ or a 75% reduction. Now for the case of a uniformly increasing load as shown in Figure 3, the losses are

$$P_{\mathrm{DL}}^{\mathrm{I}} = \frac{I_0^2 R}{l^2} \int_0^l (2lx - x^2)^2 dx = \frac{8}{15} I_0^2 R l^3 \tag{12}$$

where the multiplier has been set to normalize the total load to $I_o l$ with the same feeder length as in the uniform case. Proceeding as in the previous and placing a unit that can supply the full load, the losses are found to be

$$\begin{aligned} P_{\mathrm{DL}}^{\mathrm{I}} &= \frac{I_0^2 R}{l^2} \left(\int_0^l (2lx - x^2)^2 dx - 2l^2 \int_y^l (2lx - x^2) dx + l^4 \int_y^l dx \right) \\ &= I_0^2 R \left(\frac{l^3}{5} - l^2 y - 2ly^2 + \frac{2}{3} y^3) \right) \end{aligned} \tag{13}$$

Differentiating with respect to y and setting the result to zero gives the optimal placement of the unit to be $y = 0.293l$ with losses reduced by 88% from the original system. It is not surprising that more significant loss reduction can be achieved for the non-uniform distributions of load, nor that the best location for such a system will be towards the end of the feeder. Of course, other factors, such as, convenience for maintenance, may prevent application in remote areas.

4.3 Placement on select feeders

Placement of DG units on practical distribution feeders was investigated for four feeders chosen based on the results of the transmission system analysis. Units were placed to achieve the lowest loss using an exhaustive algorithm that searched among selected locations. These sites were chosen from densely loaded areas that receive power over a long distance. Losses were investigated using one large unit of 1 MW, 2 units of 500 kW and 4 units of 250 kW. Table 4 shows the change in real and reactive power losses for the placement of four 250 kW units on each of the four feeders. Note, there is some overlap in the models of the distribution feeder and the transmission system at the 115 kV level so that the net change in losses is not simply the sum of these and those in Table 2. Reactive power loss, although outside the investigation here, is shown as it represents potential improvements in voltage support. Very large reductions in losses can be seen on feeders one and four as there are large lumped loads that can be served locally by DG units. In the best case (feeder four), total losses were reduced by 394 kW effectively increasing the added capacity of the four 250 MW units by 39%. These losses are consistent with our analysis of feeders with uniformly increasing load.

Table 4 Distribution system losses
(a) without DG units

Feeder	115 kV		13.2 kV	
	kW	kVAR	KW	kVAR
1	0.41	3.98	6.65	4.26
2	0.85	12.68	24.02	16.02
3	21.49	322.40	58.78	112.78
4	337.13	40.62	96.85	22.49

(b) with placement of four DG units

Feeder	115 kV		13.2 kV	
	kW	kVAR	kW	kVAR
1	0.05	0.71	3.26	1.96
2	0.24	3.55	18.48	10.72
3	11.91	178.68	28.71	54.83
4	13.84	207.51	26.08	55.55

5. Conclusions

This study shows that proper location of DG units can have a significant impact on their effective capacity. Even transmission system losses can cause the useful capacity to vary by as much as 10%, with losses actually increasing for many apparently reasonable locations. Not surprisingly the impact on distribution systems is even more pronounced. Optimal siting on a feeder depends greatly on the load distribution along the feeder. In practice, there will be many limitations to the choice of sites and optimality will likely not be possible. Still, the analysis here suggests that the net thermal losses arising from different placement varies greatly, and further, that one must consider both transmission and distribution effects when determining appropriate locations.

Acknowledgements

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