Implications of On-Site Distributed Generation for Commercial/Industrial Facilities

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***Abstract*—Next-generation distributed generation (DG) is poised to become a key element in our energy future. Recognizing the increased need for a higher reliability energy system and a cleaner environment, this paper presents a technique that helps to identify the impact of grid-connected DG on the reliability of on-site electric power. This analysis shows the optimal DG mix at various facility outage costs with and without an emission restriction. The impact of varying the grid reliability and the capital costs of DG units on the decision to invest in backup power is discussed. The break-even costs of microturbines are also estimated at various facility outage costs and microturbine forced outage levels.**

***Index Terms*—Distributed generation, environmental implications, loss of load probability, on-site reliability.**

I. Nomenclature

$avai_j$	Yearly availability of generating unit j.
C_j	Discounted capital cost of generating unit j ($).
EF_{jm}	Emission factor of generating unit j, emission type m (lb/MWh).
$EF_{limit,m}$	Emission cap of emission type m (lb/MWh).
$ELDC$	Equivalent load duration curve.
FC_{jysi}	Discounted fuel cost of generating unit j in year y, season s and hour i ($/kWh).
FOR_j	Forced outage rate of generating unit j.
$ILDC$	Normalized inverse load duration curve.
j	Index for internal combustion engines, gas turbines, microturbines, fuel cells, and electricity from the grid ($j = 1, \ldots, n$).
L_0(x)	Original inverse load duration curve or *ILDC*.
$load_{ysi}$	Load in hour i, season s, year y (kWh/h).
$LOLP$	Loss of load probability.
M	Any large number.
η_{inv}	Inverter efficiency.
OC_y	Discounted facility outage cost in year y ($/h).
OM_{jysi}	Discounted operation and maintenance costs of unit j in year y, season s and hour i ($/kWh).
P_j	Unit size of generating unit j (kW).
S_j	Salvage value of generating unit j ($).
θ_{ysi}	Number of operating hours in year y, season s and hour i (hours).
U_{jysi}	Power generation from generating unit j, year y, season s and hour i (kW).
X_j	Integer decision variables, representing the number of generating units j.
Y	Year ($y = 1, \ldots, 10$).

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II. Introduction

The U.S. electric power system delivers a nearly uninterrupted flow of energy with 99.9% reliability [1]. Despite its successful history, the U.S. electric utility industry is undergoing a major restructuring. This transition has resulted in a degradation of electric service in various locations. Spurred by the blackout in the northeastern U.S. in August 2003, as well as the load shedding and electricity price spikes in California in early 2001, there is a heightened awareness of reliability issues among certain commercial and industrial customers. One of the near-term solutions for this is to install distributed generation (DG).

DG is the primary subject of various publications [2]–[5] and is widely recognized as a means to increase on-site reliability. However, no valuation method is currently in use for measuring the reliability benefits of DG; thus, no suggestion can be made about the suitable size and type of DG technologies to increase power reliability for commercial and industrial facilities. This paper presents a new approach for the optimal design of grid-connected DG systems to satisfy on-site reliability and environmental requirements. The DG units considered include ones that have been commercially proven, i.e., internal combustion engines and gas turbines, as well as ones that are being introduced today such as microturbines and fuel cells driven by natural gas.

III. Reliability and DG

Reliability is usually measured against a baseline maximum of 100% for 365 days per year. The U.S. power grid historically delivers 99.9% uptime or "three nines of power", which is equivalent to between eight and nine hours of outages per year. Table I illustrates the relationship between the degree of reliability and the time without power.

Higher degrees of reliability are increasingly required in specific high-technology customer classes for whom the effects of outages can cause tremendous financial losses. For example, outage costs are estimated at $41 000/h in the cellular-communications industry, $90 000/h in the airline-reservations industry, and as high as $6 480 000/h in brokerage operations [6]. This justifies the use of on-site DG as a quickly implemented solution that allows customers to obtain higher reliability energy than is available from traditional electric power systems.

TABLE I
RELIABILITY AND OUTAGE DURATION

Reliability	Outage Duration
99.9% (3 nines)	8.76 hours/year
99.99% (4 nines)	52.6 minutes/year
99.999% (5 nines)	5.2 minutes/year
99.9999% (6 nines)	31.5 seconds/year

Fig. 1 shows how DG can be configured for use in combination with the utility grid to provide reliable power. Under normal conditions, a customer's electrical load is powered by electricity from the utility. When a utility disturbance occurs, an uninterruptible power supply (UPS), which generally provides short-term power from batteries, is often used to sustain the load until backup sources can start. When the UPS detects a disturbance, a power electronics switch (PES) opens and disconnects the load from the utility, and the load is transferred to the UPS. The time the UPS takes to sense the problem and switch to itself is less than a quarter of cycle [7]. If the disturbance persists beyond a certain period of time, standby power sources are activated. The transfer switch then shifts to the back-up sources, the PES closes and smoothly transfers the load from the UPS to the generators. Although simple in concept, the system design must be properly configured and sized.

IV. DATA SOURCES AND ASSUMPTIONS

A. Data Sources

The economic and performance (technical and emissions) datasets for DG technologies are summarized in Table II. The capital and operation and maintenance (O&M) costs are obtained from the California distributed energy resource guide [8]. The equipment lifetime and efficiency of each DG unit are obtained from a report prepared for the U.S. Department of Energy [9]. The start-up times of internal combustion engines (ICs), gas turbines (GTs), and microturbines (MTs) are obtained from [10], and information for fuel cells (FCs) is obtained from [8]. Although MTs have a slow start-up time, they have a relatively fast dispatch estimated at 20 s [11]. Excluding ICs, the start-up time can be a technical barrier to the adoption of fossil-fired DG. This is because the ability to operate immediately, if the units are not on standby, would place a large demand on UPS size. In our analysis, we assume that UPS units are available at the facility and are able to sustain the demand until DG units can be brought online.

The availability and forced outage rates (FOR) for ICs and GTs are obtained from [12]. The availability for MTs and FCs are obtained from [9]. Since MTs and FCs are very new to the market, there is no reliable FOR data. We therefore estimated these numbers based on manufacturer information to be 0.5%. Table II also shows emission values for DG units, which are acquired from the Regulatory Assistance Project [13]. Notice that since ICs and MTs could burn alternate fuels, i.e., oil or methane, the actual emissions and cost performance of a unit may differ from the values specified. The distribution service charges, electricity supply demand charges and kWh charges used in our model are from schedule GS-2T, Virginia Electric and Power Company [14]. Average emission data from the

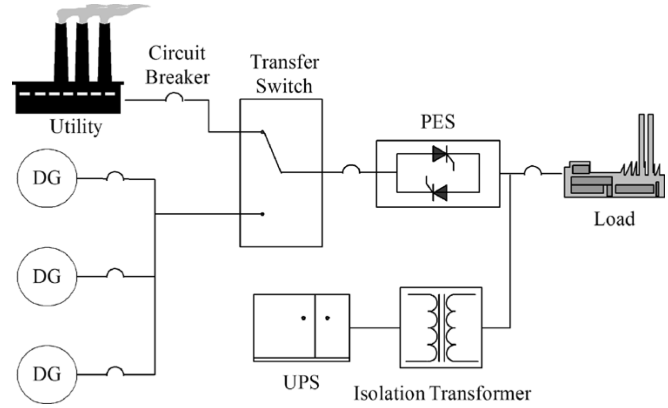

Fig. 1. A possible configuration of on-site distributed power supply systems that can be used in combination with the utility grid to provide reliable power.

grid in Virginia is obtained from the Environmental Protection Agency [15].

B. Distributed Generation Input Data

The following discussion summarizes the assumptions and parameters of the DG units used in the model. The capital and O&M costs for each DG unit are the averages of those shown in Table II: \$600/kW and \$0.011/kWh for ICs; \$650/kW and \$0.007/kWh for GTs; \$900/kW and \$0.001/kWh for MTs; and \$3750/kW and \$0.0075/kWh for FCs. The lifetime of each DG unit is shown in Table II: 20 years for ICs and GTs and 10 years for MTs and FCs. The efficiency of each DG unit is the average of those shown in Table II: 33.5% for ICs, 29.5% for GTs, 25.5% for MTs and 38% for FCs. The availability of each DG unit is the average of those shown in Table II: 93.5% for ICs, 91.7% for GTs, 95% for MTs, and 90% for FCs. The FOR of DG units used are 5.4% for ICs, 4.3% for GTs, and 0.5% for MTs and FCs. Notice that the estimated FOR values for MTs and FCs are very low as compared to the FOR values for ICs and GTs. This is especially important as we were unable to find good reliability data for MTs and FCs. Though the values used are representative, an error in these values could skew the results.

In addition to the capital costs and O&M efforts for DG units stated above, other associated expenditures are the transformer and distribution costs. Since the DG output voltage is available from 110/190 to 347/600 VAC, it can be selected to be the same as that of the facility. This eliminates the use of transformers, and for this reason, no transformer cost is included in the calculation. However, if the facility were to sell the electricity it produced to the grid, a transformer would be required and its cost must also be included in the optimization. Other distribution costs are those of low voltage circuit breakers, which are very small compared to the investment costs and life cycle O&M costs of DG units. Thus, they are neglected in the model.

C. Demand and Supply Characteristics

At the hypothetical facility used as an example, the peak demand is assumed to be 1000 kW. The off-peak demand is assumed to be 700 kW. The inverse load duration curve (ILDC) of the facility is as shown in Fig. 2(a). The existing grid capacity is 1000 kW. It is also further assumed that ICs, GTs, and MTs are available in multiples of the 500-kW units, and FCs are available

TABLE II
CHARACTERISTICS OF DG TECHNOLOGIES

Technology	Internal Combustion (IC) Engine	Gas Turbines (GT)	Microturbines (MT)	Fuel Cells (FC)	Electricity Grid
Costs:					Distribution service charge: [f] $26.17/mo and $3.387/kW. Demand charges: Jun - Sep: $6.429/kW Oct - May: $4.84/kW KWh charges: Peak: 3.155c/kWh Off-peak: 0.524c/kWh
Unit Costs ($/kW)[a]	300-900	300-1000	700-1100	2800-4700 [b]	
O&M Costs ($/kWh)[a]	0.007-0.015	0.004-0.010	0.005-0.016	0.005-0.010	
Other Characteristics:					
Fuel type	Natural gas	Natural gas	Natural gas	Natural gas	
Equipment Life [b]	20 years	20 years	10 years	10 years	
Start-up time (cold start)[c]	10 secs	10 mins	2-5 mins	< 0.1 hr	
Electrical efficiency (HHV) [b]	30-37%	22-37%	23-28%	30-46%	
Availability (%)	91.2-95.8 [d]	90-93.3 [d]	95[b]	90[b]	
Forced outage rate (FOR %)	4.7-6.1 [d]	2.1-6.5 [d]	0.5*	0.5*	0.1
Emissions: [e]					
NOx (lb/MWh)	4.7	1.15	0.44	0.03	2.54
SOx (lb/MWh)	0.454	0.008	0.008	Negligible	5.83
PM-10 (lb/MWh)	0.78	0.08	0.09	Negligible	n/a

[a] See [8]; [b] See [9]; [c] See [8], [10] and [11]. [d] See [12]; [e] See [13] and [15]; [f] See [14]; * Estimated based on manufacturer information.

in multiples of the 200-kW units. This is feasible as a number of 200-kW Phosphoric Acid Fuel Cell power plants have been operated by DOD at various U.S. sites. Note that ONSI currently only supports the Model PC25C and no longer supports the Models PC25A and PC25B [16].

This model is generic and can be applied to any user-specified DG sizes and any user-specified demand curves that can be expressed in a piecewise linear form.

V. Optimization Model

A. Objective Function

There are two design objectives, which are: 1) to minimize the total system life cycle cost and 2) to minimize outage costs incurred over the ten-year project life. This is a multi-objective problem with two opposing goals. That is, a step toward improving one of the objectives (decreasing installation costs of the system) is a step away from improving the other (increasing outage time and outage costs of the facility). The problem is formulated as a mixed-integer linear program, written in C++ with CPLEX as an optimizer. The following equation illustrates the objective function.

Minimize

$$\sum_{j=1}^{n}(C_j - S_j)\cdot X_j + \sum_{j=1}^{n}\sum_{y=1}^{Y}\sum_{s=1}^{S}\sum_{i=1}^{I}(OM_{jysi} + FC_{jysi})\cdot U_{jysi}\cdot\theta_{jysi} + \sum_{y=1}^{Y} OC_y \cdot LOLP \cdot 8760. \tag{1}$$

The decision variables are the number of generating units of type j (X_j), the hourly energy output of each generating unit in each year, season and hour (U_{jysi}) and loss of load probability (*LOLP*), which is a linear function of the decision variables X_j. The capacity of generating units of type j (P_j) and the hourly demand of the facility ($load_{ysi}$) are predefined by the user. The objective function comprises three elements. The first element is the sum of the discounted capital costs (C_j) minus the discounted salvage values (S_j) of all power generating technologies. The second element is the sum of the discounted operating costs, which include the *O&M* (OM_{jysi}) and fuel costs (FC_{jysi}) of each unit in each year, season, and hour. The last element is the sum of the discounted annual outage cost per hour (OC_y) multiplied by ($LOLP \cdot 8760$), which is expressed in number of hours per year. The next section explains how *LOLP* is derived in terms of X_j.

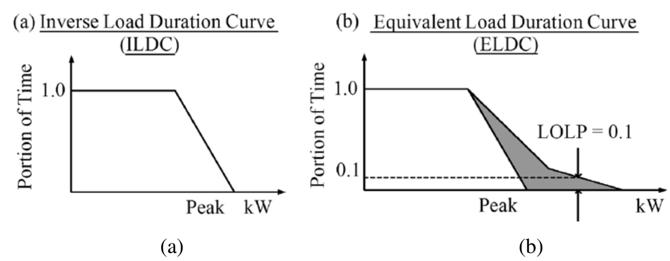

Fig. 2. (a) Normalized ILDC and (b) ELDC of the hypothetical facility.

B. Derivation of LOLP

LOLP is defined as the fraction of time in which the available capacity is insufficient to serve the daily peak or hourly load. Typically, *LOLP* can be determined after computing the entire equivalent load duration curve (*ELDC*) of the last loaded unit. To find *ELDC*, the original inverse load duration curve (*ILDC*) needs to be modified to reflect the increased demand for generation resulting from the forced outages of previously loaded units. The height of *ELDC* at the capacity point of the system represents the system *LOLP* as shown in Fig. 2(b). Alternative methods described in the literature include the indirect method [17], Fourier and fast Fourier transform [18], z-transform [19], and Monte Carlo technique [20]. In our paper, we propose the calculation of *LOLP* expressed in linear form using a convolution technique. This is based on the assumption that the probability distribution characterizing the forced outages of the unit is a uniform distribution and the *ILDC* can be expressed as a piecewise linear function. Instead of determining the entire *ELDC*, we construct the *ELDC* seen by the last loaded unit only at the capacity point of the system. To derive *LOLP*, we start with the recursive formula shown in (2).

$$L_1(x) = a_1 \cdot L_0(x) + (1 - a_1) \cdot L_0(x - P_1) \quad (2)$$

$$\cdots\cdot$$

$$L_{n-1}(x) = a_{n-1} \cdot L_{n-2}(x) + (1 - a_{n-1}) \cdot L_{n-2}(x - P_{n-1}) \quad (3)$$

$$L_n(x) = a_n \cdot L_{n-1}(x) + (1 - a_n) \cdot L_{n-1}(x - P_n) \quad (4)$$

Here, $L_j(x)$ is the value of *ELDC* seen by unit j ($j = 1, \ldots, n$) evaluated at the demand x (kW); $a_j = 1 - FOR_j$; and P_j is the capacity or size in kilowatts of unit j. As previously mentioned, *LOLP* is the value of *ELDC* seen by the last loaded unit at the capacity point of the system. This is equivalent to $LOLP = L_n(x)$, where $x = \Sigma(P_j X_j)$. Thus, the goal is to find $L_n(x)$ in terms of the original inversed load duration curve ($L_0(x)$), and evaluating this function at $x = \Sigma(P_j X_j)$. This can be done by substituting $L_{n-1}(x)$ and $L_{n-1}(x - P_n)$ in (4) with $L_{n-1}(x) = a_{n-1} \cdot L_{n-2}(x) + (1 - a_{n-1}) \cdot L_{n-2}(x - P_{n-1})$ and $L_{n-1}(x - P_n) = a_{n-1} \cdot L_{n-2}(x - P_n) + (1 - a_{n-1}) \cdot L_{n-2}(x - P_n - P_{n-1})$ from (3). This substitution process continues until $L_n(x)$ is in the form of $L_0(x)$. This equation allows us to express *LOLP* as the linear function of decision variables X_j, and to integrate *LOLP* in the objective function as shown in (1).

VI. Constraints

The following are constraints to the optimization problem.

A. Energy Balance Constraints

The hourly energy demand must be satisfied by the amount of energy generated from all DG units. For all y, s, and i

$$\sum_{j=ACsources} U_{jysi} + \eta_{inv} \cdot \sum_{j=DCsources} U_{jysi} \geq load_{ysi}. \quad (5)$$

B. Yearly Generation Constraints

For all DG, their yearly energy generation may not exceed their availability. For all j

$$\sum_{s=1}^{S} \sum_{i=1}^{I} U_{jysi} \times \theta_{ysi} \leq avai_j \times 8760 \times P_j \times X_j. \quad (6)$$

C. Individual Capacity Constraints

For all DG units, their hourly outputs are limited by their total generating capacity. For all i

$$U_{jysi} \leq P_j \times X_j. \quad (7)$$

D. Emission Constraints

The total annual emissions produced must be limited by a certain amount. The variable m represents nitrogen oxide (NO_X), sulfur oxide (SO_X), carbon dioxide (CO_2) or any other pollutant of interest. EF_{jm} is the associated emission rate of the generating unit j in pounds per megawatt hour (lb/MWh)

$$\sum_{j=1}^{n} \sum_{s=1}^{S} \sum_{i=1}^{I} U_{jysi} \times EF_{jm} \leq \sum_{j=1}^{n} \sum_{s=1}^{S} \sum_{i=1}^{I} U_{jysi} \times EF_{limit,m}. \quad (8)$$

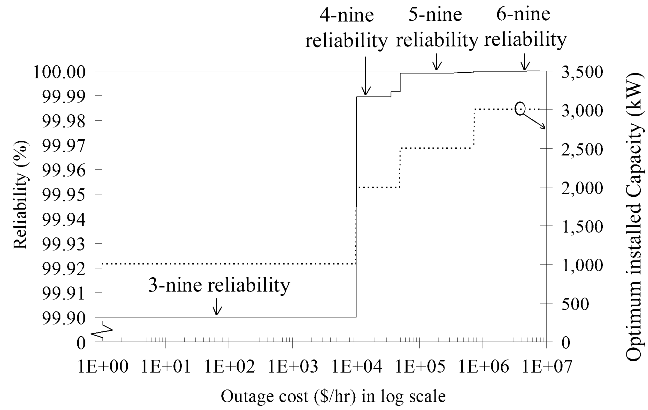

Fig. 3. Plot of optimal solutions (the optimal installed capacity and the associated system reliability) versus facility outage cost.

VII. Results and Discussions

A. Optimal Mix of Distributed Generation

Two issues were investigated related to the design of grid-connected power systems for the example facility: 1) what type of DG should be used to increase the on-site electricity supply reliability and 2) what type of DG should be installed with the presence of a NO_X regulation standard. To explore the former, the model is run to find the optimal mix of on-site DG and the associated system reliability at various outage costs from \$0/h to \$10 million/h, as shown in Fig. 3. To investigate the latter, the model is run with the NO_X emission constrained to at an annual average of 0.5 lb/MWh, as shown in Fig. 4. Note that the 0.5 lb/MWh NO_X cap is California's permitting standard for small-scale standby generation [21].

From Fig. 3, the optimal installed capacity for facilities with outage costs less than \$10 000/h is 1000 kW. The associated system reliability is 99.9%. This implies that for facilities with outage costs less than \$10 000/h, backup power is not economically desirable. In contrast, the optimal installed capacity for facilities with outage costs greater than \$10 000/h is greater than 1000 kW. As a result, the associated system reliability is greater than 99.9%. This implies that facilities with outage costs greater than \$10 000/h do require higher supply reliability, which can be provided by installing on-site DG.

The suggestions for DG installations are as follows.

- *A 4-nine reliability system for facilities with outage costs \$10 000-\$50 000/h:* The 4-nine reliability system can be obtained from the use of 1000-kW grid with 1000-kW DG. Optimal DG solutions are (2 × 500-kW ICs) or (2 × 500-kW GTs) or one of each. These systems can increase grid reliability from 99.9% to 99.989 492% with

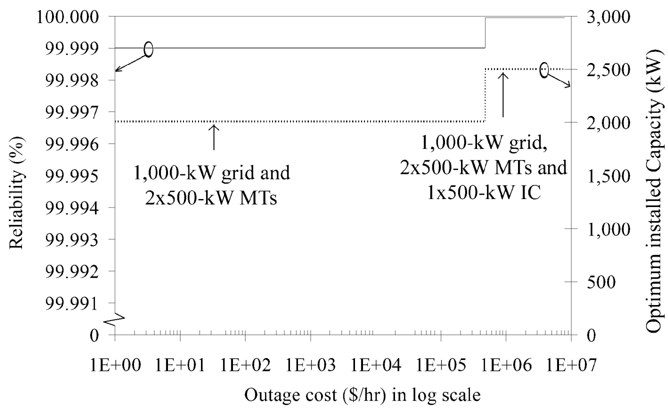

Fig. 4. Plot of optimal solutions (the optimal installed capacity and the associated system reliability) versus facility outage cost with the 0.5 lb/MWh NO_X cap.

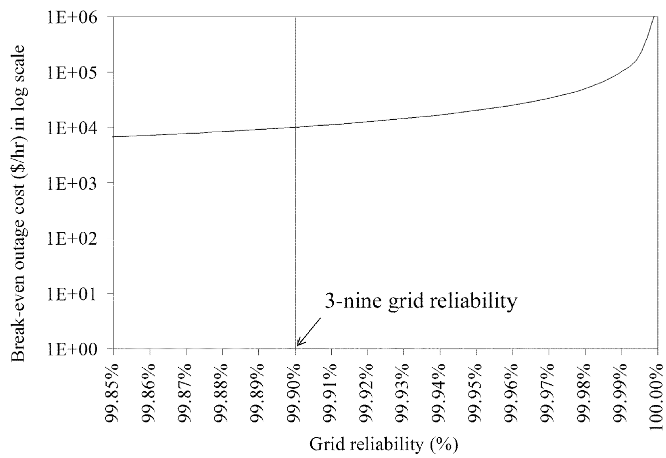

Fig. 5. Impact of variation in the grid reliability on the break-even outage cost.

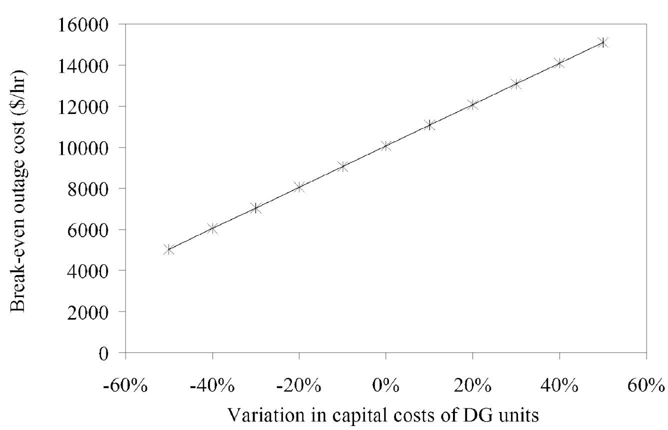

Fig. 6. Impact of variation in DG costs on the break-even outage cost.

2×500-kW ICs and to 99.991 584% with 2×500-kW GTs.

- *A 5-nine reliability system for facilities with outage costs \$50 000-\$700 000/h:* The 5-nine reliability system can be obtained from the use of 1000-kW grid with 1500-kW DG. Optimal DG combinations are (3×500-kW ICs) or (2×500-kW ICs and 1×500-kW GT) or (1×500-kW IC and 2×500-kW GTs) or (3×500kW GTs). These systems can provide reliability up to 99.999 371% using 1000-kW grid and 3×500-kW GTs.
- *A 6-nine reliability system for facilities with outage costs \$700 000/h-\$10 million/h:* The 6-nine reliability system can be obtained from the use of 1000-kW grid with 2000-kW DG, which can be from ICs or GTs or both. These systems can provide reliability up to 99.999 969% using 1000-kW grid and 4×500-kW GTs.

Fig. 4 shows the optimal installed capacity and the associated system reliability when the NO_X restriction is present at various outage costs. For facilities with outage costs up to \$475 000/h, the optimal installed capacity is 2000 kW. This includes the use of 1000 kW from the grid with 2×500-kW MTs. This system can increase on-site reliability from 99.9% to 99.999%. For facilities with outage costs greater than \$475 000/h, the 1×500-kW IC is selected in addition to the grid and the 2×500-kW MTs. This system can increase on-site reliability to 99.999 943 8%. Note that the 2×500-kW MTs selected are operated at their rated capacity and the existing grid is only used as backup power. This is in order to mitigate the NO_X emitted from the grid since the average NO_X emission from traditional generating units in Virginia is 2.541 lb/MWh, whereas that from MTs is 0.44 lb/MWh. Notice, however, that the emissions produced by MTs can drastically increase when MTs operate at lower power outputs.

It is also important to note that all solutions presented above are based on the assumptions in Section II-B and II-C and at a grid reliability of 99.9%. Recently, concerns have been raised in the U.S. over the installation of fossil-fuel based DG that can decrease overall emissions but cause local emissions to increase. There are, however, no mechanisms to take into account the emissions displaced, other than regulating the emissions from stand-by generating sources.

B. Sensitivity Analysis

Apparently, facility outage costs and environmental restrictions are the key driving forces of the DG investment decision. We define the "break-even outage cost" as the outage cost that makes it worthwhile for the facility to install backup power on-site. As Fig. 3 suggests, the break-even outage cost of this facility is \$10 000/h at a grid reliability of 99.9%. That is, if the facility outage cost is less than \$10 000/h, backup power will not be required; if the facility outage cost is greater than \$10 000/h, DG will be cost-effective when added to the existing grid power.

In the U.S., although the average outage duration of the grid is estimated at 99.9% or about 8 h per year, the actual outage duration in the systems where industrial/commercial loads are located is evidently much less. In this section, we analyze the impact of variation in the grid reliability number on the break-even outage cost, as shown in Fig. 5, and the impact of variation in the capital costs of DG units on the break-even outage cost, as shown in Fig. 6.

The result indicates that the break-even outage cost of a facility is greater than \$10 000/h when the grid is more reliable than 99.9%, and that the break-even outage cost of the facility is lower than \$10 000/h when the grid is less reliable than 99.9%. For example, when the grid reliability number is 99.99%, the facility will not require DG installation when its outage cost is less than \$100 000/h. On the other hand, if the grid reliability number is 99.985%, the facility will require backup power at the outage cost of \$6750/h.

The break-even outage cost also varies with the fluctuation in the capital costs of DG units. Fig. 6 illustrates this relationship when the capital costs of all DG units are varied from 50% to 150% from their base capital costs. The base capital costs refer to those in Section IV-B. From Fig. 6, at low capital costs of DG units, it is worthwhile to install DG at the lower facility outage cost. For example, if the capital costs of all DG units decrease by fifty percent, the outage cost for determining when the facility should install backup power will decrease to \$5000/h. On the other hand, higher DG capital costs will result in an increased value of the break-even outage cost.

C. Break-Even Capital Cost of Microturbines

Without the $\mathrm{NO_X}$ cap, MTs and FCs have not been selected at all as back-up power due to their higher investment costs than ICs and GTs. In this section, the break-even capital cost of MTs is estimated at various facility outage costs to see the price of MTs so they can compete with ICs and GTs at the grid reliability number of 99.9%. Notice that a similar analysis could also be done for FCs.

Fig. 7 illustrates the break-even capital cost of MTs at various facility outage costs and at MTs forced outage levels of 0.1%, 0.5%, and 1.0%. To determine the break-even capital cost of MTs at a specific facility outage cost, the optimization model described in Section V is used. Then, we gradually decrease the capital cost of MTs until at least one MT unit is selected in the optimal solution, while other factors (the discounted salvage value, the discounted O&M cost, and the discounted capital cost and the FOR of each technology) remain constant. The capital cost, when at least one MT unit is selected, is the break-even capital cost of MTs.

Based on this methodology, at the optimum there are two competing systems: the system with ICs or GTs and the system with at least one MT unit. When at least one MT unit is selected in the optimal solution, the value of the objective function in (1) must be less than or equal to the case when ICs or GTs are selected.

Notice from (1) that the break-even capital cost of MTs are mainly influenced by the capital costs of other technologies, the discounted O&M costs and the pre-determined FOR of each technology. The FOR of each technology selected in the optimal solution will determine LOLP of the overall system, which consequently determines the third element in the objective function. And it is this element that determines the upward or downward slopes of the MT break-even capital cost curve in Fig. 7, as described next.

As an example, in Fig. 7 at $\mathrm{FOR} = 0.5\%$ when the facility outage cost is less than \$50 000/h, we have an upward slope; and the two possible optimal mixes are the grid with 2 × 500-kW ICs or the grid with 2 × 500-kW MTs. The former can increase the grid reliability to 99.989 49%, whereas the latter can increase the grid reliability to 99.999 00%. Since the system with MTs is more reliable, with the increase in facility outage costs per hour, element three of the objective function, when MTs are selected, will increase at a slower rate (lower LOLP) than when ICs are selected. Since the objective function of the system with MTs must be less than or equal to that with ICs at the optimum, this implies that the capital cost of MTs will have a certain margin to increase with the increase in facility outage costs (upward slopes), as long as the optimal system with MTs is more reliable than that with ICs.

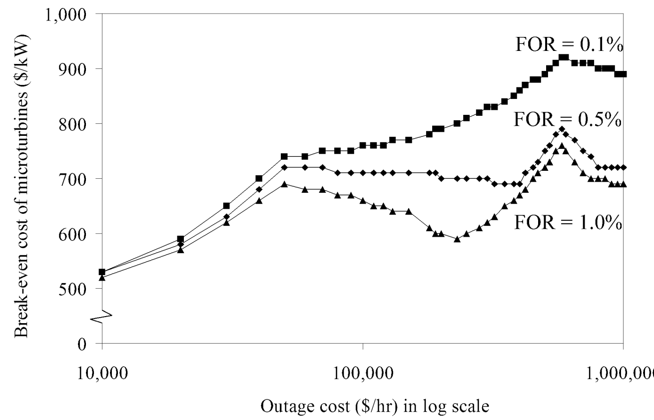

Fig. 7. Break-even capital cost of MTs versus facility outage cost per hour at MT's forced outage levels of 0.1%, 0.5%, and 1.0%.

Then, at $\mathrm{FOR} = 0.5\%$ when outage costs are between \$50 000/h and \$400 000/h, the two possible optimal solutions are the grid with 3 × 500-kW ICs or the grid with 2 × 500-kW MTs. The former can provide reliability up to 99.999 16%, whereas the latter can provide 99.999 00% reliability. Since the system with MTs is less reliable because of fewer units, with the increase in the facility outage cost per hour, element three in the objective function, when MTs are selected, will increase at a faster rate (higher LOLP) than when ICs are selected. This implies that, with the increase in the facility outage cost, the break-even capital cost of MTs must be decreased (downward slopes) to compensate for the greater ability to prevent outages of ICs, as long as the optimal system with MTs is less reliable than any optimal system with ICs.

In summary, Fig. 7 suggests that MTs with a lower FOR can cost more than ones with a higher FOR at the same facility outage cost. In addition, the capital cost of MTs at $\mathrm{FOR} = 0.5\%$, must reduce to about \$520/kW-\$790/kW (for a facility with outage costs ranging from \$10 000/h to \$1 000 000/h) so MTs could be cost-effective solutions for on-site installation.

VIII. Conclusions

A model to determine the optimum mix of on-site grid-connected DG with respect to reliability and environmental requirements is presented and demonstrated. Without the emission restriction, ICs and GTs are the only technologies selected due to their low initial cost. MTs show promise when $\mathrm{NO_X}$ emissions are of major concern. FCs are still too expensive to be selected as optimal solutions even when the $\mathrm{NO_X}$ cap is introduced. The results indicate that DG investment decisions depend heavily on grid reliability levels, initial costs of DG units and the presence of environmental regulations. The model is also used to estimate the break-even capital cost of MTs at different outage costs and forced outage levels. As an extension to this work, further research can be carried out to quantify other benefits of DG, including issues of power quality and combined heat and power.

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