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AVOIDING DISTRIBUTION SYSTEM UPGRADE COSTS USING DISTRIBUTED GENERATION

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Abstract

The Pacific Northwest National Laboratory (PNNL), in cooperation with three utilities in the Western United States, developed a database and methodology to analyze and characterize the avoided costs of distributed generation (DG) deployment as an alternative to traditional (or conventional) distribution system investment. Project summaries ("cases") were obtained from each utility and used to generate capital, operations, maintenance, and centralized power generation costs.

The utility cases fell into two broad categories: upgrades of existing distribution systems and new distribution system construction. Project case proposals covered a broad spectrum of traditional technical solutions, ranging from the installation of capacitors and new conductors to the construction of new substations.

After applying a number of screening criteria to the initial set of 307 cases, 18 were selected for detailed analysis. Alternative DG investment scenarios were developed for these cases, spanning a broad spectrum of cost, problem to be solved and technical approach. These DG system options were defined in sufficient detail to permit capital, operations, maintenance, and fuel costs to be identified and incorporated into the analysis. In addition, the "customer-owned" backup power generator option was investigated.

DG configurations using combustion turbines were found to be more costly than those using spark-ignition, internal combustion reciprocating engines. Reciprocating engines were selected in 16 of the 18 cases examined. Combustion turbines were only considered in two cases that involved large step growth functions requiring significant capacity upgrades. The economy of scale limitations associated with the reciprocating engine option limited its applicability in these cases.

The results of the analysis of the 18 cases show that none of the alternative DG scenarios yielded cost savings when compared to the conventional investments. However the degree of success of the DG alternative was found to depend greatly on the geographic area served by the project, the

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estimated load growth rate for the substation where the investment occurred, the size of the upgrade and the project type. For example, DG alternatives were more competitive in absolute terms in rural projects and in capacity enhancement projects. In addition, the DG alternative systems were configured using very restrictive assumptions concerning reliability, peak rating, engine types and acceptable fuel. In particular it was assumed that the DG alternative in each case must meet the reliability required of conventional distribution systems (99.91% reliability). This constraint requires redundancy in the design of the DG configurations, with extra engines and turbines being included for reliability purposes.

The analysis was further constrained by a requirement that each substation meet the demands placed upon it by a "one in three year" extreme weather occurrence. Thus, each DG alternative must not only meet current demand but also demand that might be placed upon it under periodic extreme weather conditions. To determine if, by relaxing these requirements, the DG alternative might be more viable, the projects were re-examined. The 99.91% reliability factor was still assumed for normal operating conditions but the redundancy required to maintain reliability was relaxed for the relatively few hours every three years where extreme weather caused load to exceed present substation capacity. This reduced the number of power generators required for the projects and resulted in deferment of capital investment until later years. The cost of both the conventional and DG alternative also dropped because the centralized power generation, variable O&M, and DG fuel costs were calculated based on present load in combination with long-term forecasts of load growth. This basis was less severe than requirements based on present load levels plus a buffer based on predictions of extraordinary weather conditions. Application of the relaxed set of assumptions resulted in a 12% decrease in the average cost of the DG alternative for the 18 cases ($47.0 million to $41.2 million). The average cost of the conventional investment was $25.1 million.

Thus, the results of analysis of the 18 cases reflect the limitations of the small sample size and scope of the data, coupled with the stringent requirements imposed on the DG configurations. Analysis of a much larger set of cases that represent the country as a whole and that exhibit the most advantageous combinations of area served, project type, load growth and size of upgrade, is warranted.

This paper also explores the feasibility of using a system of backup generators to defer investment in distribution system infrastructure. Rather than expanding substation capacity at substations experiencing slow load growth rates, PNNL considered a scenario where diesel generators were installed on location by customers participating in a program designed to offer additional end user power security and reliability. The backup generators, in turn, could be used to meet peak demand for a limited number of hours each year, thus deferring distribution system investment. Data from an existing program at one of the three participating utilities were used to quantify the costs associated with the backup generator scenario. The results of the "customer owned" backup power generator analysis showed that in two of the four cases examined the total present value costs of the alternative backup generator scenarios were between 15 and 22% less than those for the conventional scenarios. Thus, the additional costs of connecting diesel generators to the grid were more than offset by the present value savings associated with deferring distribution system investment into the future.

Overall, the results of the study offer considerable encouragement that the use of DG systems can defer conventional distribution system upgrades under the right conditions and when DG configurations are intelligently designed. Using customer-owned DG to defer distribution system upgrades appears to be an immediate commercially-viable opportunity.

1. Introduction

Distributed generation (DG) and other distributed energy resources (DER) are believed to have the potential to avoid or defer capital investment for new distribution system capacity, offsetting the current marginally higher cost of these resources compared to centralized generation. The potential avoided distribution system costs are a strong function of the type of load growth, the nature of the capacity bottlenecks, the capital cost of the distribution upgrade, the certainty that the expected load growth will actually materialize, and other financial variables. Pacific Northwest National Laboratory (PNNL), in cooperation with three utilities in the Western United States, developed a database, methodology and an analysis tool to analyze and characterize the avoided costs of DG deployment as an alternative to traditional distribution system investment.

This paper presents and discusses the results of the life cycle cost comparison of both actual and proposed utility distribution system upgrade and expansion investments and alternative proposed DG deployments using the Distributed Energy Cost Analysis Model (DECAM), developed by PNNL. Technical, cost, and system data were used by DECAM to quantify all capital, operations, maintenance, fuel, centralized power generation, income and property tax, insurance premium and line loss costs associated with each investment scenario. The approach and model developed for this study are straightforward and readily adaptable for use by utility engineers, planners, and regulators in the evaluation of DG options when considering distribution system upgrades and expansions.

The paper is divided into seven main sections, with the first being this introduction. The second section describes and discusses the process and the results of selecting projects for detailed analysis. The third section discusses technical considerations concerning establishing the capacity increase for each case and the main requirements for the DG configurations. Section 4 presents the cost analysis methodology, while section 5 describes the results of the analysis. Section 6 considers the use of customer-owned backup engine generators in place of conventional upgrades. The seventh and final section presents conclusions.

2. Project Selection

Through the cooperation of three utilities in the Western United States, PNNL obtained engineering and cost data for 307 conventional distribution system upgrade and new construction projects undertaken between 1995 and 2002 or planned during the 2003-2011 timeframe. The location of the projects ranged from remote rural to densely-populated urban areas and their costs ranged from a few thousand to several million dollars. The format and completeness of the data varied greatly; therefore further analysis and interpretation of the data were required to extract the necessary information. This information included total capital cost, capacity increase, line ampacity (the current in amperes a conductor can carry continuously under the conditions of use without exceeding its temperature rating) and the capacity enhancement technical classification of each project. The extracted information was entered into a master database.

The projects were sorted into eight broadly defined capacity enhancement categories (or capacity enhancement technical classifications) as follows:

1. Capacitors: Install either fixed or switched capacitors to provide power factor improvement and/or local voltage support.
2. Load Transfers: Install small tie lines and/or switches to transfer load to another source. This source can be in the same substation or a completely separate substation.
3. New Feeders: Install new feeders to utilize the capacity of an existing substation.
4. New Line: Install new lines to connect substations or feeders to improve system reliability and/or transfer load.
5. New Substation: Build a new substation to serve load growth and/or increase reliability when other alternatives cannot meet demand.
6. New Transformer: Install new transformers or replace existing transformers at an existing substation.
7. Reconductoring: Replace the existing feeder line with a higher ampacity feeder or replace an aged line with a new line.
8. Substation Capacity Increase: Increase substation capacity by installing new or improved existing devices, such as transformer fans and oil pumps.

Certain projects were particularly challenging to classify because they incorporated upgrades falling into a number of categories. In each of those cases, judgment was exercised to select the most appropriate category.

Screening

The projects were passed through three screening steps to define a set of project cases where it was believed that DG could be both technically and financially feasible as an alternative to the conventional distribution system upgrade. The screening process reduced the number of cases selected for detailed analysis to 18.

Screen 1: Incomplete data. Information provided for 119 cases did not include all of the data required for detailed analysis. Assembling the missing data was not possible because of time and resource constraints. This screen reduced the number of cases from 307 to 188.

Screen 2: Cost, size, multiple related projects, replacement of outdated equipment and complex functional requirements. Projects having costs below $150,000 were eliminated because simple inspection showed that DG alternatives were not feasible. Projects that involved capacity increases greater than 60 MVA were deemed to be beyond the generally accepted range of DG. In some instances it was found that different projects in different categories were mutually related and designed to meet a common objective. These projects were combined into a single project. The choice of category in each instance was based on the importance of the contribution of each individual project to the overall objective. The capacity increase for each combined project was recomputed. Projects that were required to satisfy complex reliability needs or a combination of load growth and complex reliability needs were eliminated. In some cases transformers and other substation equipment had to be replaced. The DG option was not viable for these cases. This screen reduced the number of cases from 188 to 42.

Screen 3: Ready access to pipeline supplied natural gas to fuel either combustion gas turbines or spark ignition reciprocating engines. Application of this screen reduced the number of cases from 42 to the final 18 that were analyzed in detail.

It is interesting to note that for a few projects the customer's exceedingly high reliability requirement was the investment driver. In each of those projects, the proposed or actual capacity increase greatly exceeded the load growth requirement. That is, significant redundancy was integral to the planned upgrade. For example, in one case a dedicated substation was built to serve a high-tech company plant expansion. While the expected load increase was only 20 MVA, the substation was designed to have three different transmission line sources and two 28 MVA transformers. The capital cost for the project was $4,647,298 (about $232/kVA of actual load increase served). This is much higher, on the basis of $/kVA of increased load, when compared to projects where meeting load growth, while maintaining the existing overall reliability, was the driver.

It was found that for projects aimed at power factor (PF) correction (mainly capacitor projects), the average PF before installing capacitor bank(s) was 0.90, with 0.84 being the lowest value found. The goal of each project of this type was to increase PF to at least the minimum value required by the utility.

Table 1 shows the number of projects and total capacity of projects falling into each category before and after the first screen. It can be seen that most of the surviving cases fell in the categories of reconductoring (7), capacitors (1), new transformers (6), and load transfers (2). The numbers in parentheses in the table refer to the original 307 projects, while the numbers outside of parentheses refer to the number of projects that survived the first screen. The breakdown of cases following the second screen is shown in Table 2.

Table 1 Breakdown of Project Cases by Category Following the First Screen

Category	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**Total**
Number of Cases	37(57)	29(53)	17(22)	12(21)	11(12)	36(37)	43(99)	3(4)	188(307)
Capacity (MVA)	80	155	235	76	40	763	489	22	1859

Table 2 Breakdown of Project Cases Following the Second Screen

Category	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**Total**
Number of Cases	4	3	5	0	8	20	2	0	42

Discussion of the Results of the Screening

Table 2 shows that the new substation (5) and transformer (6) categories ("winning" categories) account for 2/3 of the cases selected for detailed analysis. The range of individual project costs in these two categories was $0.3 to about $4.7 million. No cases in categories 4 and 8 ("losing"categories) survived. Following is a discussion of the results of the second screen.

Winning Categories

Category 6 (New Transformer): This category is believed to be the most probable for DG alternatives to compete with the traditional upgrades. A total of 20 cases in this category survived for the final screen. Typically, in this category, new transformers are installed to serve load growth and/or reliability problems in the service territory. When a new transformer is installed, other necessary accompanying equipment (switch gear, feeders, breakers, etc.) also needs to be installed. The combined cost is therefore greater than that of the transformer(s) alone. This, of course, improves the competitiveness of DG alternatives, especially for projects in which the main objective of the upgrade is to serve the load growth and the reliability problem involved is not very complex. Individual project costs for the 20 selected cases in this category ranged from $300,000 to $4,684,388.

Category 5 (New Substation): A new substation also includes new transformer(s), so the arguments in favor of DG alternatives for category 6 are also true for category 5. The main difference between the two categories is that category 5 requires a new site and major site preparation from scratch, while category 6 utilizes the existing facility with far less site preparation required. Hence, the cost of projects in category 5 is typically higher than in category 6. The cost range for the eight selected cases in category 5 was $2,209,075 to $4,715,888.

Losing Categories

Category 8 (Substation Capacity Increase): These projects involve improving existing equipment or installing new fans and oil pumps on substation transformers to increase their capacity. This type of upgrade is definitely not suitable for DG alternative consideration because of the low cost and no site preparation requirement. The traditional costs for the three cases considered in this category ranged from only $3,917 to $120,440.

Category 4 (New Line): This category includes projects where small capacity distribution lines are installed. Usually, cases in this category involve solving reliability problems and transferring load from one feeder to another (either in the same substation or a different substation). The traditional costs for the 21 cases considered ranged from $45,000 to $750,000. DG alternatives cannot compete in this category because of complex functional requirements and low costs for the traditional solutions.

Category 1 (Capacitor), 2 (Load Transfer), 3 (New Feeder) and 7 (Reconductor): From a technical feasibility perspective, DG alternatives are possible in these categories. However, DG cannot compete from the economic perspective because of the very low incremental cost per unit of additional capacity provided by these conventional upgrades. Projects in these categories are also often mutually related to achieve a specified objective. For example, a load transfer project is often accompanied by a reconductor project, a new feeder project, a new line project, or a combination of such measures. A capacitor project, or a load transfer project, or both, are commonly related to a new feeder project. When such projects are combined, the resulting capacity increase is usually less than the sum of the capacity increases enabled by individual projects. Often, the capacity increase achieved corresponds to only one of the constituent projects, while the combined project cost is the sum of individual project costs. Thus the opportunity for the DG alternative to successfully compete with the combined conventional upgrade is greatly improved.

The third and final screen eliminated projects where natural gas was not available by pipeline to fuel either combustion gas turbine generators or spark ignition, reciprocating engine generators.

3. Technical Analysis

Capacity Increase

The focus of the technical analysis of the project data was to establish the capacity increase for each case. Without reliably establishing the magnitude of the capacity increase, detailed analysis could not be carried out. Because of the greatly differing data formats among the three utilities and the wide variety of project objectives, the capacity increase value was often not readily evident. Engineering knowledge and judgment were applied to extract the necessary information.

To extract the capacity increase for each project, it was necessary to develop a number of working assumptions, as follows.

Power Factor Correction Projects

When the PF target was not specified, it was assumed that the goal of PF correction was to increase PF to 0.95, the minimum requirement of one of the three utilities. It was assumed that the capacitor banks were installed on the secondary side of the substation transformer and as close to the load as possible. It was further assumed that the difference between the load voltage before and after installing the capacitor bank(s) was negligible. After installing capacitor bank(s), the current (and hence, the apparent power) flowing on the primary side was assumed to decrease. The difference between the kVA value before and after the installation of the capacitor(s) was assumed to be the capacity increase.

Load Transfer Projects

For load transfer projects, the following were assumed:

- Feeders with the same name but different identification numbers were assumed to be in the same substation. For example, feeders XYZ 12 and XYZ 14 are in the same substation.
- Load transfer between existing feeders in the same substation does not count as capacity increase, but it does count when installing a new feeder and transferring load from other feeders to the new one.
- When transferring load from one substation to another, the amount transferred is assumed to be the capacity increase.
- Load swapping between phases of the same circuit does not count as capacity increase.

New Feeder Projects
When a new feeder (or a new line) is installed, it was assumed that the capacity increase is the full capacity of the new feeder (or line) regardless of the substation capacity to which the new feeder (or line) is connected.

New Line Projects
When replacing a line with one having a larger capacity, the capacity increase was assumed to be the difference between the thermal loading of the new line and the old one regardless of the substation capacity to which the line is connected.

New Substation Projects
For new substations, the capacity increase is simply the total added transformer capacity.

New Transformer Projects
The capacity increase is the capacity of the transformer or transformers added. Where one or more existing transformers are replaced, the capacity increase is the difference between the new total capacity installed and the total capacity removed.

Reconductoring Projects
The capacity increase in these cases was assumed to be the difference between the ampacity of the new line and that of the line being replaced.

Substation Capacity Increase
For these cases the capacity increase was determined by the capacity enabled through the installation of new or improved existing cooling augmentation devices.

Assumptions Used in Configuring the DG Alternatives
For each project that made it to the final analysis, a DG alternative was configured to solve the problem as stated in the project description. The assumptions used in constructing the alternative DG configurations were fairly restrictive. Three major requirements were set out and adhered to in configuring the DG alternative for each of the 18 cases:

1. The DG alternative in each case must meet the same reliability requirements as the conventional distribution system upgrade (99.91 percent reliability) for each MW served by the project. This constraint leads to redundancy in the design of the DG scenarios with extra engines and turbines being included for reliability purposes.
2. Each substation must meet the peak load demand placed upon it by a “one in three year” extreme weather occurrence. Thus, each DG alternative must not only meet current demand but also demand that might be placed upon it under periodic extreme weather conditions.
3. In principle, a number of power generating technologies are available for DG applications. However, only combustion turbine generators and spark-ignition, reciprocating engine generators were considered. They were deemed to be commercially mature – that is, reliable, widely accepted, readily available and featuring the lowest cost.
4. To permit continuous engine generator operation (essentially “base load” operation) in the face of air quality requirements, the only DG configurations considered were those using combustion turbines or spark-ignition, reciprocating engines fueled by natural gas provided

by pipeline. On-site storage of either liquid or gaseous fuel and possibly frequent fuel deliveries were deemed to be unlikely to be approved by local authorities.

4. Cost Analysis Methodology

This section provides an overview of the cost analysis methodology developed for this study. The methodology was designed to analyze the extent to which DG could serve as an economic alternative to traditional distribution system upgrades. The cost analysis methodology developed for this study was applied to a systematic, retrospective review of 18 distribution system upgrades either implemented between 1995 and 2002 or projected for the 2003-2011 timeframe.

The dataset constructed for this study included the 18 projects that survived the screening process described above. Project summaries were obtained for each project, with each summary including capital cost, engineering and other descriptive information. Additional data required to perform the cost analysis were obtained, including:

- the after tax weighted cost of capital
- effective property and income tax rates
- insurance premiums
- long-range load estimates by substation
- operations/maintenance costs
- capital and operations/maintenance cost escalation rates
- the availability of natural gas on-site
- load duration curves by substation
- line losses
- centralized power generation costs

Each project was taken at face value. That is, the study only compared DG alternatives to those investments as actually planned or carried out by the utility, rather than considering other conventional distribution system investment alternatives. Further, the analysis was performed based on present-day DG technology and forecasts for technology advancements, without consideration of the technology available at the time the project was actually completed. In this manner, the study effectively compares historical investments to current DG technology. Therefore, the cost analysis is more relevant to future investment decisions, and should not be used retroactively to challenge decisions made in the past.

Distributed Generation Alternatives

The engineering information contained within the project summaries was used in conjunction with load data and other planning assumptions to generate alternative DG investment scenarios. For each DG alternative, capital, fixed O&M, variable O&M and fuel costs were identified and analyzed. Initial load requirements and long-term load growth were estimated at the substation level by the partner utility, and DG investments were designed to meet peak load requirements during the analysis timeframe for each project.

The DG alternatives designed for this study use natural-gas-fired combustion turbine generators and spark-ignition, reciprocating engine generators. When the DG alternative called for units of

5 MVA or less, natural-gas-fired spark-ignition, reciprocating engines were used. Combustion turbines were used when units of more than 5 MVA were required to meet forecast load requirements.

Both the initial capital and annual O&M cost estimating equations are based on electricity generating systems only. Thermal cogeneration requirements would result in additional costs. Also, the combustion turbine costs and performance are based on non-recuperated systems. The use of recuperators, which are common with micro turbines but much less so for intermediate-sized combustion turbines, would significantly increase both costs and efficiency.

Other technologies often associated with distributed generation include fuel cells, micro turbines, diesel-fired reciprocating engines, wind turbines and solar photovoltaic (PV) generators. Each of these technologies has niche applications; however, they suffer from the following limitations in the context of the applications that were investigated:

- Fuel cells are currently available from only one supplier (200 kW) in the size range of interest and cost, on a $/kW basis, 5 to 10 times more than gas turbines and reciprocating engines. Even so, a fuel cell could be the preferred DG option in applications where minimum noise and emissions were most important.

- Micro turbines, nominally covering a power range of 25 to 200 kW, are too small for the cases considered.

- Diesel-fired reciprocating engines have competitive cost and performance characteristics, but emissions and fuel costs were considered too high for the annual operating hours required by the applications being considered.

- Wind turbines and PV cannot provide the reliability (power on demand) required without additional backup power supplies or energy storage units.

Sources of Information

The cost and performance equations for this study were developed from a review and evaluation of published information sources. The single most significant sources used were reports prepared by Onsite Sycom Energy Corporation for the U.S. Department of Energy's Energy Information Administration. These reports provided detailed information regarding purchase and installation costs, annual operating and maintenance costs, and performance for several different technologies over the applicable size range for each. Other key sources of information were obtained from E Source, the National Energy Technology Laboratory (NETL), Resource Dynamics, and the California Energy Commission.

Initial Capital Cost

The cost equations presented below are intended to represent the total cost of purchasing and installing the distributed generation equipment. This includes the purchase of the engine generator unit, electrical and other ancillary equipment, site engineering work, installation materials and installation labor. Also included are costs associated with system engineering, construction management, and a construction contingency allowance.

Actual site-specific costs could easily vary by +/- 20% from the costs predicted by these equations. Variances in site-specific electrical and natural gas connection requirements create the greatest cost uncertainty, but differences in the prices offered by different vendors at different times in different locations contribute significantly to cost uncertainty as well. The equations are representative of the costs applicable in the year 2000. (In equations 1, 2, 5, 6, 7 and 8 that follow, "kW" represents generating capacity in kilowatts.)

$$\text{Combustion Turbine Installed Cost} = \$11{,}173 * (\text{kW})^{0.721} \qquad (1)$$ [1]

$$\text{Reciprocating Engine} = \$2{,}302 * (\text{kW})^{0.8496} \qquad (2)$$ [2]

Operations and Maintenance Cost

Operations and maintenance costs were split into fixed and variable components. The fixed component is incurred every year regardless of the number of operating hours, while the variable component is proportional to electrical energy (kWh) generated. Combustion turbines and reciprocating engines will incur periodic maintenance costs associated with major component overhauls; however, these costs have been incorporated into the O&M cost equations, in keeping with the source data.

Most of the O&M costs are associated with the hot, moving components of the heat engines. Therefore, one would expect less site-specific variance in O&M requirements compared to initial capital requirements. However, because O&M cost experience is generally less well documented than initial capital cost experience for most technologies, O&M cost uncertainty may be similar to that described above for capital costs. Once again, the cost equations are generally representative of costs applicable in the year 2000.

$$\text{Combustion Turbine Fixed Annual O\&M Cost} = \$27{,}215 + 4.117 * \text{kW} \qquad (3)$$

$$\text{Combustion Turbine Variable O\&M Cost} = \$0.004/\text{kWh} \qquad (4)$$

$$\text{Reciprocating Engine Fixed Annual O\&M Cost} = \$902 * \text{Ln}(\text{kW}) - \$3{,}258 \qquad (5)$$

$$\text{Reciprocating Engine Variable O\&M Cost} = \$0.0233 * (\text{kW})^{-0.1209}/\text{kWh} \qquad (6)$$

Electrical Conversion Efficiency

Electrical conversion efficiency generally increases with generating capacity, but also varies for different models at the same capacity because of subtle, but important differences in design. Often, more efficient designs come with a price premium, but such is not always the case. In general, the efficiency predicted for a specific size is intended to represent the average efficiency, just as the estimated costs are intended to represent the average. The uncertainty in the efficiency equations is much less (perhaps +/- 5%) than for the cost equations. This stems

[1] The combustion turbine equations for capital, fixed O&M, variable O&M and electrical conversion efficiency are applicable for 500-kW to 25,000-kW turbines.

[2] The reciprocating engine equations for capital, fixed O&M, variable O&M and electrical conversion efficiency are applicable for 100-kW to 5,000-kW engines.

from generally less sensitivity of rated performance to site-specific conditions. However, actual performance will vary with site-specific conditions, particularly for combustion turbines.
Heat engine efficiencies are most commonly reported in the literature based on the lower heating value (LHV) of the fuel, which ignores the heat of condensation of water vapor in the combustion products. Fuel prices (expressed in $/MMBtu), however, are invariably reported on a higher heating value (HHV) basis. For natural gas, LHV is 10% less than HHV. Thus, it is very important to ensure that efficiency and fuel prices are estimated on the same basis. The following equations predict conversion efficiency based on the HHV of natural gas, which results in values 10% lower than commonly reported in the literature.

$$\text{Combustion Turbine HHV Efficiency} = 0.0773 * (\text{kW})^{0.1428} \quad (7)$$

$$\text{Reciprocating Engine HHV Efficiency} = 0.2373 * (\text{kW})^{0.0561} \quad (8)$$

Technology Advancement

The cost and performance of combustion turbines and reciprocating engines have continually improved as a result of enhancements in design, installation, and efficiency. Therefore, it is reasonable to assume that the evolution of these units will continue for the next 30 years.

The technology advancement equations presented below are based on long-range cost and efficiency estimates presented in two reports prepared by Onsite Energy for the National Renewable Energy Laboratory (NREL). One report focused entirely on small combustion turbine engines and the other entirely on reciprocating engines. Based on the forecasts presented in the Onsite reports, combustion turbine improvements are expected to include advances in turbine blade and vane design, improvements in blade tip coatings, enhanced coatings for thermal barriers, and the continued evolution of heat resistant materials such as monolithic ceramics.[3] Additional cost savings could be realized through more favorable regulatory and policy environment for DG equipment, reductions in system package costs as a result of the maturing of the DG market and resultant reductions in project contingency costs in proportion to other cost reductions. Each of the aforementioned advancements was used to construct the following cost equation, with the year 2000 serving as the base year:

$$\text{Technology advancement for combustion turbines} = a * (1.01^{-x}) \quad (9)$$

Where,
a = base year cost; and
x = first year of commercial operation – base year.

As is the case with combustion turbines, reciprocating engine costs have also fallen in recent years because of technological advancements. Technological improvements anticipated for natural-gas-fired reciprocating engines in the long-term include: enhancements to engine speed, thermal barrier coating, improved engine control, advanced exhaust gas treatment, the use of enhanced heat-resistant ceramic materials, on-site installation costs reduced because of

[3] Onsite Energy / Energy Nexus Group, "Gas-Fired Distributed Generation Technology Characterizations: Small Gas Turbines", Prepared for the National Renewable Energy Laboratory and Antares Group Incorporated, Arlington, Virginia, October 2002.

standardization of design, streamlined regulatory and permitting procedures, and resultant reductions in project contingency costs. The following technology advancement equation was designed to capture these future gains:

$$\text{Technology advancement for reciprocating engines} = aX^b \qquad (10)$$

Where,
a = base year cost
X = first year of commercial operation – base year
b = -0.041.

Cost Analysis Framework

The analysis considers the costs imposed on the utility during periods of time, which vary by project. The period under examination varies by project based on load growth rates, the existing capacity of the studied substation, and the size of the upgrade. Effectively, the period of analysis includes the first year of commercial operation and every year thereafter until the load for the substation exceeds its capacity after the upgrade. Once this level is reached, the utility is faced with another investment decision that is not examined in this analysis. The period of examination ranges from a minimum of 10 years to a maximum of 40 years.

The cost analysis model constructed for this study was used to evaluate a full range of costs incurred by projects, including initial and interim capital costs, operations and maintenance costs, fuel costs, property and income taxes, insurance premiums and centralized power generation costs. Note that fuel costs and DG system requirements were estimated based on an analysis of substation-level load duration curves, trended upward in a linear manner based on 30-year load growth estimates supplied by the utility. As noted in the previous sections, the cost analysis model includes technology advancement equations designed to weight the impact of future improvements to existing DG technology on capital costs. Technology advancement factors were not considered for variable costs (e.g., O&M and electrical efficiency).

The up to 40-year timeframe considered in some projects requires the consideration of not only the present demand for energy but also demand over the next four decades. The model is designed to ensure that adequate power generation capacity exists to meet growing consumer demand, as estimated by the utility. Figure 1 shows a graphic illustration comparing a single conventional distribution system upgrade to a series of DG capital improvements. In the example case illustrated in Figure 1, additional DG capital investments are required throughout the system operating lifetime. In this case, the DG alternative enables the utility to push some of the capital investment out into later years, thus reducing its costs in present value terms. This benefit, however, is counterbalanced by the economies of scale and typically lower capital costs of conventional distribution system investments.

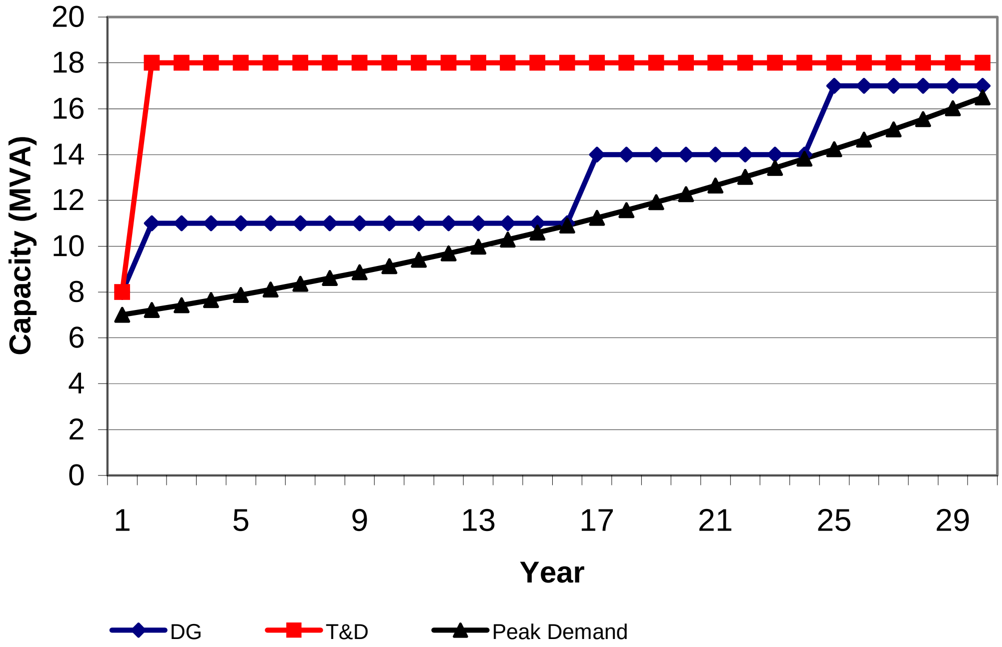

Figure 1 Conventional and DG Investment Approaches to Meet Peak Demand

The analytical framework used in this study was adapted from work performed by the California Institute of Technology (CALTECH).[4] The cost model considers all initial and recurrent costs, property and income taxes, insurance premiums and centralized power generation costs. The model expresses cost in terms of constant 2002 dollars, treats interest and inflation in a systematic manner and distinguishes between costs that occur annually and those that occur in a single year.

The cost analysis model developed for this study uses equations contained within the CALTECH report to generate total cost estimates for both the conventional and DG alternatives, with total costs expressed in a lump-sum net present value manner. To construct the cost estimates, the first step in the process was to obtain the after tax weighted cost of capital from the utility. In turn, the after tax weighted cost of capital was used to construct a capital recovery factor. The capital recovery factor represents the annual dollar amount required to fully amortize the value of a loan during a specified time period. The capital recovery factor is a function of the after tax weighted cost of capital and the system lifetime.[5] Annualized fixed charge rates were constructed for each investment. The annualized fixed charged rate captures the utility specific data – e.g., property tax, income tax, insurance premiums, and other miscellaneous costs – and interacts with capital, operations, maintenance, and fuel costs to determine annualized system-resultant costs for each investment. Annualized system-resultant costs are elaborated on later.

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[4] Doane, J., O'Toole, R., Chamberlain, R., Bos, P. and Maycock, P. "The Cost of Energy From Utility-Owned Solar Electric Systems: A Required Revenue Methodology for ERDA/EPRI Evaluations", California Institute of Technology, Pasadena, CA, June, 1976.
[5] Ibid., III-9.

The net present value of capital and recurrent costs were constructed to collapse all measured costs into single lump sum values.

The comparison of projects of unequal length posed a challenge. The DG investment scenarios often required interim capacity upgrades to the system to meet growing peak demand. DG upgrades assumed to be undertaken during the latter stages of the study timeframe often had useful lives extending beyond the time period examined in the study. To overcome this issue, present value amounts for capital and O&M were converted to annualized system-resultant costs. The annualized system-resultant cost for each investment alternative represents an amount, if received each year during the project life, would equal the present value of the project. The annualized costs were constructed in nominal terms. Annualized system-resultant costs falling outside of the analytical timeframe were excluded from the analysis because these costs were assumed to be counterbalanced by the benefits derived from the remaining productive capacity of each investment. Finally, the annualized system-resultant costs falling within the study timeframe were re-collapsed back into present value terms using the utility's after tax weighted cost of capital as the discount rate.

5. Results of the Analysis

The results of the analysis for all 18 cases selected for analysis are presented in Table 3. Table 3 shows that of the 18 projects that were analyzed as part of this study, none yielded cost savings under the alternative DG scenarios.

The first column of Table 3 lists the project number assigned to the project. The second column lists the total costs associated with the conventional distribution system upgrade project, including capital, O&M, tax, insurance, line loss and centralized power generation costs. Conventional project costs range from a low of $0.6 million to $84.8 million. The third column shows the estimated costs for the alternative DG investment scenarios, which range from a low of $4.2 million to a high of $172.5 million. The fourth column compares the costs associated with the DG and distribution system option. The fifth column presents a ratio comparing DG project costs to conventional costs. Note that the average DG alternative costs roughly 86 percent more than the average conventional alternative included in this study.

In analyzing these results it is important to note that a simple reference to the cost ratios shown in Table 3 is insufficient to draw any concrete conclusions about the success of the DG alternative. For example, the projects with the smallest ratios are projects 2012 (1.41), 2026 (1.45), and 2050 (1.47); however, these projects are among the most significant losers in terms of absolute cost differences at $34.0 million, $24.8 million, and $18.4 million, respectively. In each case, these projects involve heavy variable components that blend out the up-front losses as a result of capital cost differentials. That is, the variable cost differential, which is consistently around 10 to 20%, increases the absolute losses incurred under the DG alternative but washes out larger capital cost differentials when the projects are planned for heavy use, such as is the case for new substations.

Table 3 Project Cost, Geographic Area, Load Growth, Size and Type

Project ID	Total Cost Conventional Alternative	Total Cost DG Alternative	Conventional Alternative - DG Alternative	DG Alternative / Conventional Alternative	Geographic Area Served	Load Growth Rate	Size of Upgrade (MVA)	Project Type
2001	$11,828,577	$22,601,276	($10,772,698)	1.91	Rural	2.1%	12.5	New Transformer
2002	47,835,325	83,308,946	(35,473,621)	1.74	Suburban	3.9%	56.0	New Substation
2007	84,826,160	172,484,840	(87,658,679)	2.03	Suburban	3.4%	56.0	New Substation
2011	41,241,744	81,563,747	(40,322,004)	1.98	Urban	4.4%	28.0	New Substation
2012	83,648,915	117,654,101	(34,005,186)	1.41	Suburban	1.6%	28.0	New Substation
2013	3,742,766	10,683,385	(6,940,619)	2.85	Urban	3.8%	14.9	New Transformer
2015	9,331,487	24,892,320	(15,560,834)	2.67	Rural	2.8%	14.0	New Transformer
2019	12,016,727	34,306,074	(22,289,347)	2.85	Suburban	2.4%	28.0	New Transformer
2022	33,825,610	61,976,542	(28,150,932)	1.83	Urban	1.2%	20.5	New Transformer
2024	2,162,513	10,788,982	(8,626,469)	4.99	Rural	2.0%	10.6	New Transformer
2026	55,477,934	80,299,398	(24,821,464)	1.45	Suburban	2.9%	28.0	New Substation
2029	10,769,724	28,587,322	(17,817,598)	2.65	Urban	1.1%	28.0	New Transformer
2036	4,676,316	19,791,687	(15,115,371)	4.23	Urban	2.4%	28.0	New Transformer
2038	583,797	4,244,394	(3,660,597)	7.27	Suburban	1.7%	7.0	Reconducturing
2043	5,418,169	13,750,639	(8,332,469)	2.54	Urban	2.9%	28.0	New Transformer
2045	1,804,068	7,042,729	(5,238,661)	3.90	Rural	0.8%	11.6	New Transformer
2046	2,680,334	8,788,723	(6,108,388)	3.28	Suburban	2.0%	11.2	New Transformer
2050	$39,241,659	$57,683,308	($18,441,649)	1.47	Suburban	3.7%	28.0	New Substation

The cost analysis model constructed for this study compares the capital, O&M, tax, insurance, line loss, financing and power generation costs associated with both the conventional distribution system upgrade and the DG alternative for each project. A further discussion of the analysis approach and the interpretation of the results is provided below using Project 2001 as an example.

For Project 2001, the conventional alternative entails the installation of a 10/12.5-MVA distribution transformer complete with two feeder positions, 36,000-KVAR capacitor banks, 115-kV circuit breakers, and line disconnects. The total cost of this equipment is $1.3 million ($2003). Additional costs associated with project financing and allowances for property and income taxes increase the total capital costs to over $1.9 million. In this case, the after tax weighted cost of capital is 8.34%, the allowance for property taxes and insurance is 1.5%, the general rate of inflation is 2.3%, and DG capital and O&M escalation rates are also 2.3%. The conventional approach exhibits an additional $0.5 million in O&M and $9.4 million in centralized power generation costs. Both estimates are expressed in constant 2002 dollars.

The DG alternative entails the installation of 13 1-MVA natural gas-fired reciprocating engines over the life of the project, with two units being installed in 1996, 2000, 2009, and 2016, and five units installed in 2021. Note that the capacity of the DG alternative grows slowly but more than equals the capacity of the conventional distribution system approach in the final year of the analysis time frame. The total cost of the DG alternative is $22.6 million, roughly twice that of the conventional alternative. The DG alternative costs more in total capital costs, which are roughly $10.8 million in constant 2002 dollars. The DG option is also more costly in terms of variable costs at $11.8, compared to $9.9 million in the conventional alternative.

The results of this analysis suggest that the utility collaborating with this study would not have benefited from the deployment of the DG alternatives. However, each project presented a different set of conclusions with respect to the degree of the success of the DG alternative. Table

3 provides additional information relating to each project, including the geographic area served by the project, the estimated load growth rate for the substation where the investment occurred, the size of the upgrade and the project type. On average, the rural projects included in the analysis cost less ($16.3 million) than the suburban ($70.6 million) and urban ($36.1 million) projects. These costs include all the aforementioned cost categories, including centralized power generation costs for the load served by each project. As a result of their smaller size and cost, in addition to the slow growth rates for many rural projects, DG alternatives were more competitive in absolute terms there than in suburban or urban settings. The DG alternatives were also more competitive in capacity enhancement projects (i.e., new transformers, reconductoring), as opposed to new substations. The DG alternatives were not competitive in the new substation cases because of the significant initial capital costs and the high load requirements of the area served by the new substation. DG solutions meet only incremental load requirements in capacity enhancement projects.

The output of the cost analysis model suggests that the primary benefit of deploying DG as opposed to the conventional investment was the deferral of capital costs. These costs, however, were more than offset in each case examined in this study by the greater up-front capital costs associated with DG technology. Figure 2 compares the capital cost curves constructed for combustion turbines and reciprocating engines to the actual capital costs associated with 51 of the projects included in the data set. The cost curves for the combustion turbines and reciprocating engines shown below are not specific to any of the 18 projects analyzed in detail in this study, but are rather the output of the aforementioned DG capital cost curves for units of various sizes. The curves in Figure 2 also reflect that the equations for the DG alternatives are constrained by the unit size. That is, the reciprocating engine equations apply only to engines of 100 kW to 5 MW while the combustion turbine equations apply to units of 1 MW to 25 MW. Figure 2 shows that a 28-MVA substation upgrade, including transformer, line and other supporting upgrades, costs between $1 and $5 million in capital costs, whereas a 25-MVA combustion turbine generator unit is estimated to cost nearly $17 million. Note that combinations of smaller combustion turbine generators would yield similar results. Also note that in each case, the variable costs – which are not shown in Figure 2 – under the DG alternative (fuel and variable O&M) exceeded those of the conventional alternative associated with centralized power generation costs.

Figure 2 also shows that the combustion turbine alternative was more costly than the reciprocating engine option. In turn, reciprocating engines were selected in 16 of the 18 cases examined. Combustion turbines were only used in two cases that involved large step growth functions requiring significant capacity upgrades. The scale limitations associated with the reciprocating engine option limited its applicability in these cases.

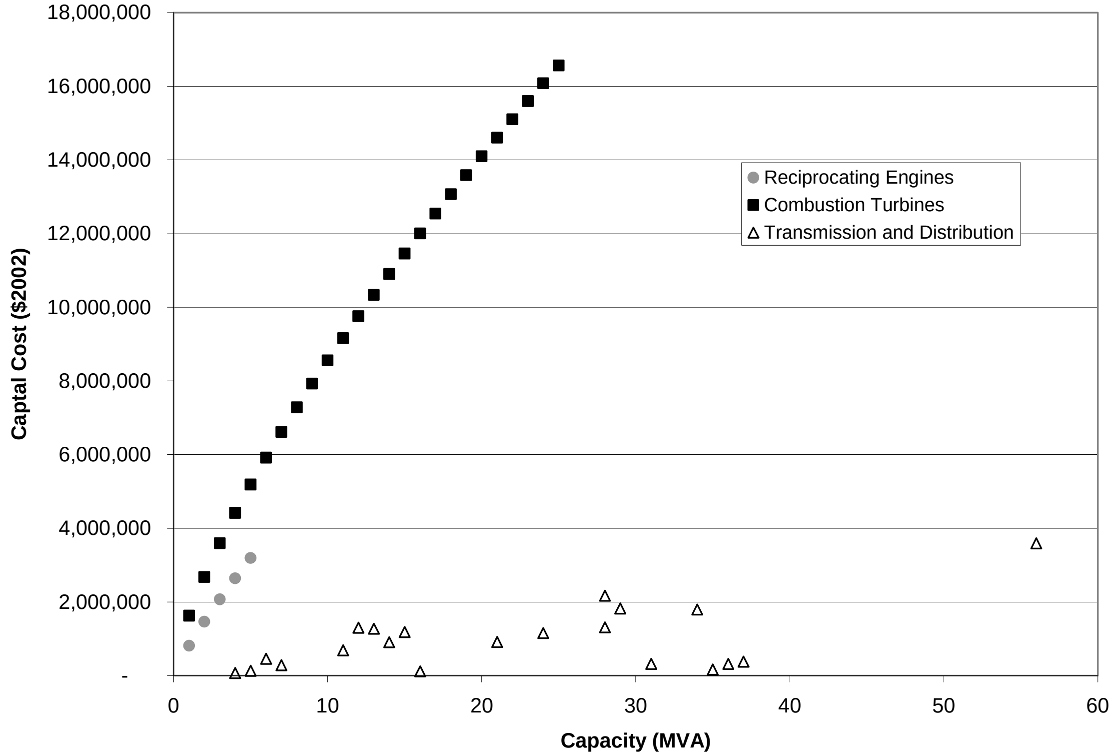

Figure 2 Comparison of Conventional and DG Capital Costs

The DG alternative systems analyzed in this study were configured using very restrictive assumptions concerning reliability, peak rating, engine types and acceptable fuel. In particular it was assumed that the DG alternative in each case must meet the reliability required of conventional distribution systems (99.91% reliability). This constraint leads to redundancy in the design of the DG configurations, with extra engines and turbines being included for reliability purposes. The analysis was further constrained by a requirement that each substation meet the demands placed upon it by a "one-in-three year" extreme weather occurrence. Thus, each DG alternative must not only meet current demand but also demand that might be placed upon it under periodic extreme weather conditions.

To determine if relaxing these standards would make the DG alternative more viable, the projects were re-examined. The standard 99.91% reliability factor was still assumed for normal operating conditions, but redundancy required to maintain reliability was relaxed for the relatively few hours every three years where extreme weather caused load to exceed present substation capacity. In other words, a single power generator would be used as backup during extreme weather conditions and variable costs associated with demand would be based on present measurements of demand as opposed to expectations of future extreme weather conditions. This is obviously a less conservative set of assumptions.

This relaxed set of assumptions resulted in the deferment of capital investment until later years and reduced the number of engines required for the projects. The cost of both the conventional and DG alternatives also dropped because the centralized power generation costs, variable O&M,

and DG fuels costs were calculated based on present load requirements in combination with long-term forecasts of load growth, as opposed to load requirements plus a buffer based on predictions of extraordinary weather conditions.

For example, applying the relaxed set of assumptions in Project 2045 reduced the total cost of the DG alternative by about $1.7 million (from $7.0 million to $5.3 million). The reduction, however, did not change the overall result for this case because the cost of the conventional distribution system upgrade remained lower, at $1.8 million. Application of the relaxed set of assumptions resulted in a 12% decrease in the average cost of the DG alternative for the 18 cases ($47.0 million to $41.2 million). The average cost of the conventional investment was $25.1 million.

6. Analysis of Backup Generators

This section explores the feasibility of using a system of backup generators to defer investment in distribution system infrastructure. Data collected from one of the three participating utilities suggests that the utility at times makes investments in substations, transformers, and other distribution equipment not only when peak loads are expected to exceed capacity but also based on a probability analysis estimating the likelihood that peak loads under a "one-in-three year" extraordinary event (e.g., inclement weather) will exceed capacity. That is, load during any given year could be expected to remain below current substation capacity. This was demonstrated by the load duration curves supplied for each substation included in this analysis. However, investments were planned to secure enough capacity to meet load demands during spikes in load caused by weather and other extraordinary events. This requirement guarantees a high level of reliability but also necessitates an accelerated investment schedule. In the case of the participating utility, the assessment of the "one-in-three year" event was primarily based on historical load data.

Because load was only expected to exceed capacity every three years (on average) and only for a limited number of hours, it was concluded that backup generators could be used to effectively cover tri-annual spikes during which existing capacity at substations would be insufficient to meet demand. Such a strategy would result in the deferral of conventional distribution system investment until annual peak loads were forecast to exceed the sum of the capacity provided by the existing substation and the backup generators supplying power to the grid. Furthermore, in limited circumstances, the shape of the load curve was such that the number of hours where load would be expected to exceed existing capacity was small.

To analyze the impact of using backup generators to defer capital investment, two scenarios were developed for each investment undertaken:

- The first scenario assumes that no backup generators are used, distribution system capital investment is undertaken as planned, and variable costs include all operations and maintenance, as well as centralized power generation costs plus line losses.

- The second scenario entailed the installation of diesel generators on location at customers participating in a program designed to offer additional power security and reliability to the customer and connection to the grid. To participate in the program, companies must link to the grid and grant the utility the right to dispatch the units as needed up to a predetermined number of hours per year; in this case, roughly 400 hours per year. Utility access to units in this type of service is generally constrained by environmental restrictions, which limit total annual operation to approximately 600 hours per year, with 200 hours dedicated to the participating companies. This scenario assumes backup generators are installed in the first year of the analysis timeframe and the conventional distribution system investment is, therefore, not required until peak load requirements exceed the capacity of the existing substation and the backup generators.

A program currently operated by one of the participating utilities was the source of the data used in this analysis. By participating in the program, private and public sector entities access the technological capability of the utility and defray costs related to O&M and fuel, which are paid by the utility. From the perspective of the utility, additional generation capacity is produced at a reasonable cost and is accessible for a limited number of hours per year. The utility generally pays for the following items: (a) generator modifications, (b) larger fuel storage tanks, (c) revenue meters, (d) wiring and conduit, (e) communications systems, and (f) substation upgrades. Additional costs include contingency and for particularly attractive investments, various program incentives and cost reimbursements.

The primary advantage identified by the utility with respect to the use of these generators is to provide power to the grid when actual demand exceeds forecasts and spot market prices are higher than the dispatch cost of the diesel generators. The dispatch cost of the backup generators is a function of variable maintenance and fuel costs, and averages roughly $75/MWh. Thus, the backup diesel generator program examined in this paper provides a small amount of insurance against unpredictable swings in demand and spot market energy prices.

Table 4 presents three cost proposals generated by the utility for entities expressing interest in the program. It shows that the estimated cost per kW of bringing the generating capacity on-line at between $138.33/kW and $175.60/kW. Note that the estimated cost to the utility of enlisting Company C included a $100,000 reimbursement for equipment purchased by the company.

Table 4 Illustrative Cost Proposals – Backup Generator Program

Cost Item	Company A	Company B	Company C
Generator Modifications	$8,000	$60,000	25,000
Fuel Storage Tank	26,000	30,000	0
Paralleling Switchgear	93,500	99,000	147,500
Revenue Meter & Current Transformers	22,000	10,500	40,000
Wiring & Conduit	25,500	38,000	21,500
Communications	3,000	64,000	42,500
Substation Upgrades	8,500	29,700	26,600
Engineering & Design	15,000	20,000	20,000
Contingency	18,000	30,000	75,000
Cost Reimbursement	0	0	100,000
Total Utility Costs	219,500	381,200	498,100
Total Capacity (kW)	1,250	2400	3600
Total Cost / kW	$175.60	$158.83	$138.33

A total of 36 proposals were analyzed to construct the cost curves discussed later in this paper. The analysis revealed a number of key factors:

1. There are variable cost components (e.g., generator modifications, communications equipment) in the proposals; however, the variability of these costs is not directly tied to the capacity of the generator units.
2. There are costs that are largely fixed or at least do not vary significantly based on the size of the unit (e.g., engineering, fuel storage tanks).
3. Costs generally rise as the number and capacity of units installed at each site grows, but costs tend to rise at declining rates, thus demonstrating fairly significant economies of scale.

Figure 3 shows the costs identified in the 36 proposals. Because of the cost sharing nature of the program, DG units are brought on-line for approximately $100 to $200 per kW. In Figure 3, dollars per kW of generation capacity is measured on the y-axis and the capacity of the on-site generation capacity is measured on the x-axis. The data suggest a logarithmic relationship between unit cost (dollars per kW) and capacity. Equation 11 was constructed to capture this relationship, and was used to construct the curve that connects the 36 data points identified in Figure 3 and cost estimates produced for this study. It must be noted once more that Figure 3 represents the data for one utility only and should not be interpreted too broadly.

$$y = -49.082 \, \mathrm{Ln}(x) + 527.12 \qquad (11)$$

Where,
x = equipment capacity (kW)
y = unit cost of bringing the backup generators on-line ($/kW).

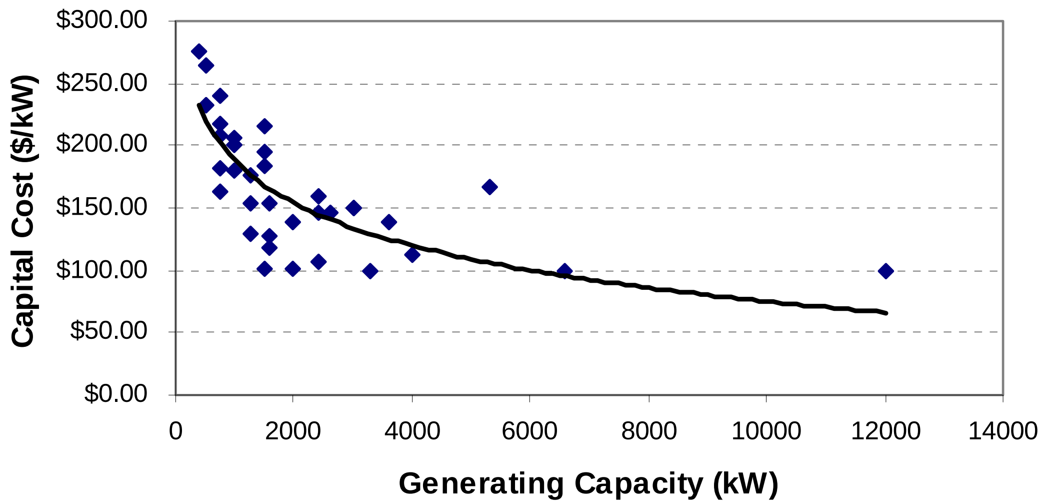

Figure 3 Capital Cost of Backup Generator Power versus Generator Capacity

As these generators are brought on-line and used to provide power to the grid, there are additional variable costs incurred by the utility. These costs include diesel fuel and variable O&M costs. Use of the backup generators does not result in any form of compensation between the utility and the participating company. Furthermore, revenue generated by the units, through the sale of energy to third parties, is kept by the utility.

Returning to the 18 cases examined previously, each was assessed with the respect to the feasibility of using backup generators, located on-site at participating companies and public agencies, to defer conventional distribution system capital investment. Of the 18 cases examined, 14 reflected system reinforcement requirements that could not be addressed by backup generators. For example, problems resolved by the construction of new substations were generally too extensive to be dealt with solely by backup generators. Furthermore, areas experiencing significant load growth, reliability problems, or significant planned area development required immediate expansion of the distribution system by conventional approaches.

Nevertheless, four cases were selected for more detailed analysis. For each case, the conventional distribution system investment scenario was compared to the backup generator distribution system investment scenario. As previously noted, the alternative scenario assumes backup generators are installed in the first year of the analysis timeframe and the conventional investment is, therefore, not required until peak load requirements exceeds the sum of the existing substation capacity and the backup generators.

The results of the analysis are presented in Table 5. In all cases, the nominal cost of the alternative scenario is more than the nominal cost of the base-case conventional scenario. For two of the cases, however, the total present value costs of the alternative backup generator scenarios were less than those for the conventional scenarios. The analysis of Projects 2045 and 2046 resulted in estimated savings under the backup generator scenarios of approximately $390,031 (21.6%) and $413,558 (15.4%), respectively. Note that Project 2046 included feeder and a supervisory control and data acquisition (SCADA) replacement, which could not be deferred. Thus, the alternative scenario assumes that the feeder improvements and SCADA replacement would be completed as planned but that backup generators would enable the utility to defer the costs associated with transformer replacement.

The scenarios analyzed for Projects 2045 and 2046 resulted in savings because the additional up-front costs of the backup generators were exceeded by the benefits, in net present value terms, associated with deferring the higher-cost distribution system investment into the future. In each case, the distribution system annual capital escalation rate is assumed to be roughly 2.3% while the discount rate is the after-tax weighted cost of capital for the participating utility (more than 8%).

The total cost estimates presented in Table 5 represent the present value costs associated not only with capital investment, but also O&M, insurance, taxes, depreciation, and capital financing. Under the base-case distribution project scenario, cost estimates also include centralized power generation costs and line losses for the entire analysis timeframe. Where demand is served by backup generators, costs also include fuel and variable O&M for the years during which the conventional distribution system investment is deferred.

It is important to note that three of the projects selected for analysis were located in rural areas experiencing relatively slow load growth, where regional development is not presently a significant issue. Rural areas, however, are believed to be less likely to be sites for large manufacturing facilities, data processing centers, government facilities, or hospitals suitable for entering into the backup generator program. The results do suggest, however, that utilities should be cognizant of backup generation capacity that presently exists across the grid to leverage that resource, or at least propose to leverage it, as appropriate to defer expensive T&D investments. Furthermore, to the extent that the program can be justified as a device to respond to volatility in market prices for energy, the marginal cost of using backup capacity already connected to the grid to defer conventional distribution system investments would be negligible.

Table 5 Cost Savings/Losses Resulting From Backup Generator Deployment and Deferment of the Conventional Distribution System Investment

Project ID	Capital Cost of Conventional Distribution System Alternative	Total Cost of Backup Generator Alternative	Total Cost of Conventional Distribution System Alternative	Backup Generator Alternative - T&D Alternative	Savings (%)	Conventional Investment Deferral	Reason for Project	Geographic Area Served	Project Type
2001	$1,304,780	$11,125,695	$10,834,582	$291,113	-2.7%	5 years	-	Rural	New Transformer
2002	$3,590,744						New Substation	Suburban	New Substation
2007	$5,126,537						New Substation	Suburban	New Substation
2011	$4,412,888						New Substation	Urban	New Substation
2012	$5,088,121						New Substation	Suburban	New Substation
2013	$2,104,145						Reliability	Urban	New Transformer
2015	$907,283						Load Growth	Rural	New Transformer
2019	$2,255,425						Area Development	Suburban	New Transformer
2022	$913,171						Area Development	Urban	New Transformer
2024	$689,606	$2,002,655	$1,681,962	$320,693	-19.1%	8 years	-	Rural	New Transformer
2026	$2,486,183						New Substation	Suburban	New Substation
2029	$1,823,633						Load Growth	Urban	New Transformer
2036	$2,270,700						Load Growth	Urban	New Transformer
2038	$289,139						Load Transfer	Suburban	Reconductor
2043	$4,498,701						Area Development	Urban	New Transformer
2045	$849,502	$1,413,070	$1,803,101	($390,031)	21.6%	9 years	-	Rural	New Transformer
2046	$1,421,909	$2,267,116	$2,680,674	($413,558)	15.4%	7 years	-	Suburban	New Transformer
2050	$3,142,323						New Substation	Suburban	New Substation

7. Conclusions

The results of the analysis of the 18 cases show that none of the alternative DG scenarios yielded cost savings when compared to the conventional investments. However the degree of success of the DG alternative was found to depend greatly on the geographic area served by the project, the estimated load growth rate for the substation where the investment occurred, the size of the upgrade and the project type. Furthermore, the DG alternative systems were configured using very restrictive assumptions concerning reliability, peak rating, engine types and acceptable fuel. Thus, the results of analysis of the 18 cases reflect the limitations of the small sample size and scope of the data, coupled with the stringent requirements imposed on the DG configurations. Analysis of a much larger set of cases that represents the country as a whole; that exhibits the most advantageous combinations of area served, project type, load growth and size of upgrade; and where the stringent requirements are appropriately relaxed, is warranted.

Using existing customer-owned DG to defer distribution system upgrades appears to be an immediate commercially-viable opportunity. The results of the "customer owned" backup power generator analysis showed that in two of the four cases examined, the total present value costs of the alternative backup generator scenarios were between 15 and 22% less than those of the conventional scenarios. Utilities should be cognizant of backup generation capacity that presently exists across their grids to leverage that resource, or at least propose to leverage it, as appropriate to defer expensive conventional distribution system investments. Furthermore, to the extent that the program can be justified as a device to respond to volatility in market prices for energy, the marginal cost of using backup capacity already connected to the grid to defer conventional distribution system investments would be negligible.

Overall, the results of the study offer considerable encouragement that the use of DG systems can defer conventional distribution system upgrades under the right conditions and when the DG configurations are intelligently designed.

Combined heat and power (CHP) systems were not assessed in this study. Because CHP is currently the most viable market sector for DG, an assessment of the potential for existing CHP systems and new CHP installations to defer conventional distribution system upgrades is warranted.

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