Costs of Utility Distributed Generators, 1-10 MW

Twenty-Four Case Studies

1007760

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Power System Engineering Inc.

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PRODUCT DESCRIPTION

True project costs for distributed generation systems are becoming more evident as utilities deploy more units to meet customer, power delivery and peak supply needs. The twenty-four case examples in this report illustrate a range of total installed costs and highlight the key variables influencing cost. Learning from these cases utilities can take steps to ensure costs are managed and schedules met. Utility owned and operated distributed generation installations are now better understood enabling utility planners to more realistically conceive projects and better estimate total installed costs.

Results & Findings

The case studies provided good general cost information for diesel fueled reciprocating engine systems. Three cases provided information about natural gas fueled installations and one case included a gas-fired combustion turbine unit. The information was used to develop general cost-estimating guidelines, but it did not support the development of detailed costs for key project variables beyond total project capacity. Project estimators should add vendor information to the case study data to develop estimates for projects significantly different from those represented in the case studies. Nonetheless, the diversity available among the cases should assist an interested utility in defining its next steps and items to consider in its cost analysis of distributed generation.

Challenges & Objectives

Distributed generation (DG) can support power delivery systems and defer significant transmission and distribution projects. It can be used to provide backup service to local loads during grid interruptions, and provide savings by avoiding the cost of power supply demand charges during peak load periods. This potential, however, is hard to evaluate due to lack of cost data from actual projects. This report provides cost data from twenty-four actual cases of utility owned DG, where distributed generation is used for peak shaving and grid support.

Applications, Values & Use

This report provides cost estimating guidelines for potential DG projects using generators in the 1 MW to 10 MW power output range. The guidelines are developed from data supplied by utilities that have completed distributed generator installations during the past five years.

Although diesel fueled distributed generation dominates this segment of utility applications today, it is expected that natural gas fueled units will gain in popularity in the near-term and small combustion turbine and fuel cell technologies will gain popularity in the long-term.

EPRI Perspective

This report provides a unique collection of installation and operating cost experience for twenty-four actual projects completed by utilities across the United States. The report presents an analysis of these costs and provides a recommended cost estimating model for future projects.

Approach

Seventy-five utilities (where there was early indication of distributed generation use) were initially approached. Twenty-four utilities stepped forward with information about their distributed generation projects and offered to serve as case examples. Initial telephone contact was made with all candidate utilities and a formal data request was provided to receptive respondents. Follow-up contacts were made to move along responses, to clarify information requested and responses received, and to address additional questions.

Keywords

Combustion Turbine Generator
Diesel Generator
Natural Gas Generator
Distributed Generation
Distributed Generation Costing
Distributed Generation Installation
Distributed Generation Maintenance
Distributed Generation Planning
Distributed Resources
Grid Support

EXECUTIVE SUMMARY

True project costs for distributed generation systems are becoming more evident as utilities deploy more units to meet customer, power delivery and peak supply needs. The twenty-four case examples in this report illustrate a range of total installed costs and highlight the key variables influencing cost. Utilities can learn from these cases and take steps to ensure costs are managed and schedules are met. Utility owned and operated distributed generation installations are now better understood enabling utility planners to more realistically conceive projects and better estimate total installed costs.

Distributed generation (DG) installation, operating and maintenance costs can vary widely from utility to utility and from project to project within a utility. Key factors affecting the installation costs include engine-generator market price (prices have been lower than normal in late 2002 due to reduced economic activity and a strong supply of used units available for immediate purchase), project timeline (short timelines can significantly increase costs), specific site challenges (e.g. special enclosures required for noise attenuation), system interconnection requirements and project permitting requirements.

Utility project managers indicate installation costs can be managed successfully and utilities can readily outsource maintenance requirements to capable vendors to the extent desired. The case study analysis yielded:

- An overall expected investment cost of $371/kW for diesel powered generator capacity
- Total annual diesel fuel cost is estimated at $15.34 per kW for 200 hours of operation per year with fuel costing $1.00/gallon
- Annual maintenance costs average $5,000/year for a typical diesel engine driven 1,800 kW unit operating 200 hrs/year or less

Project implementation time often ranges from six to eighteen months, with a normal schedule of twelve months for a typical installation. Figure ES-1 shows a typical project schedule for a new DG project.

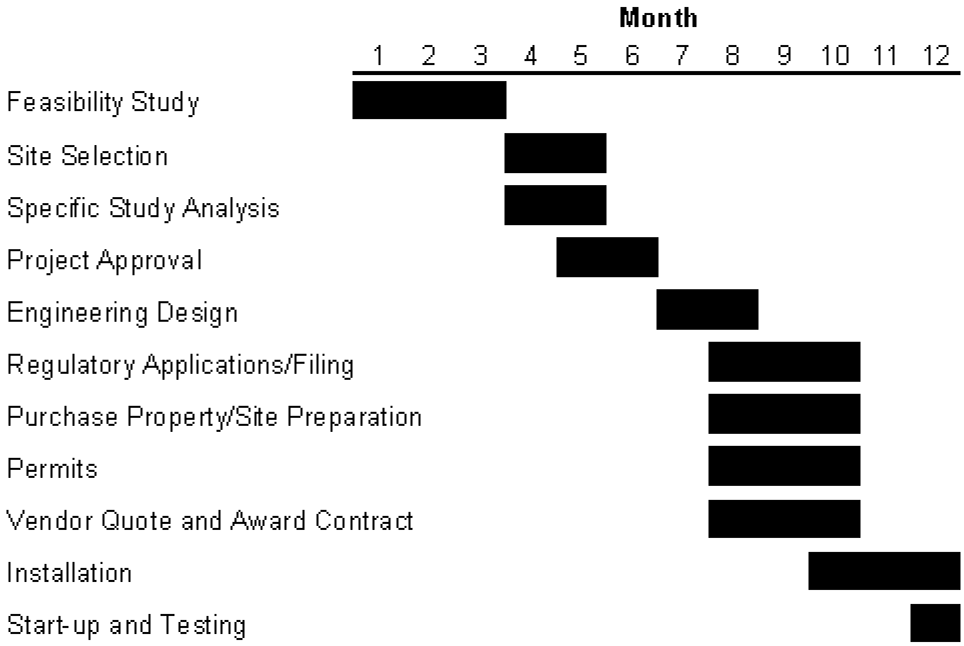

Figure ES-1
Typical Project Schedule for New Distributed Generation

Through supporting cost information and analysis, this report presents twenty-four actual cases where distributed generation was installed by utilities. More specifically, the report provides planning, installation and operational background discussion about each case to help utility planners apply the information to their own project evaluations. In addition, the report presents cost guidelines developed from the case study information for evaluating future projects ranging from 1 MW to 10 MW output per site.

Approximately seventy-five utilities (where there was early indication of distributed generation use) were initially approached. Twenty-four utilities stepped forward with information about their DG projects and offered to serve as case examples. As a group, the case examples are units sized at least one MW and no greater than ten MW, deployed for electric generation (not combined heat and power projects), and owned and operated by the local utility. Most of the distributed generators in the cases are diesel fueled engines with only a few fueled by natural gas. All are reciprocating engines with the exception of one combustion turbine. The cases include electric cooperatives, public power and investor-owned utilities.

Average size for a diesel fueled DG project is 6.2 MW (median size is 5.5 MW) at an average project cost of $371/kW (median of $378/kW). The median length of warranty is five years. The largest single item is the cost of the genset, which averages about fifty-five percent of the total project cost. A separate building enclosure is used at a minority of the sites, and (when present) the average cost is approximately eight percent of the total project cost. Switchgear and controls average about nine percent of total project cost. Extra emissions controls are required at a limited number of sites and (when required), the cost averages two percent of the total cost (although only a few cases presented this information). Lastly, the installation, indirect, and miscellaneous costs averaged nearly twenty-six percent of the total project costs. Figure ES-2 shows the typical percentage of total project cost breakdown.

During the planning phase of the distributed generation projects, time should be allotted to investigate considerations that may impact project implementation operations and costs. Examples of these considerations are: load forecasting, system compatibility, regulatory filings and service contracts. When evaluating these considerations the cases show the need to allow planning time for program approvals and budget deadlines.

The following steps are recommended when estimating the cost of potential DG project sites:

1. Obtain preliminary environmental information about the potential site concerning:
   - Is the location rural or urban?
   - Is the site relatively flat?
   - How close is the existing electrical system to the proposed site?
   - Is a pre-manufactured enclosure satisfactory or is a building required?
2. Identify the project service date.
3. Assess the DG equipment market.
4. Use the cost guides in Sections 3 and 4 to develop a baseline project estimate.
5. Review the case overviews and summaries and presented in Section 2. Compare the baseline project estimate with the reported costs for cases that are similar to the proposed project.
6. Adjust the estimate up or down as required to recognize any unique requirements of the proposed project.

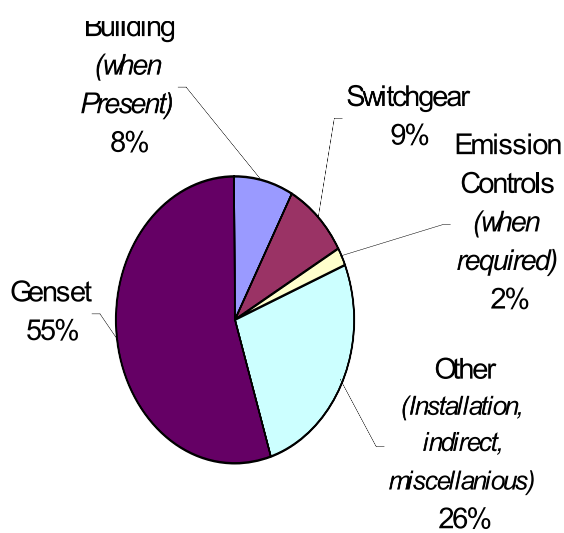

Figure ES-1-2
Typical Percentage of DG Project Cost by Component

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1
INTRODUCTION AND SCOPE

Distributed generation has been installed in a variety of applications during the past five to ten years to support power delivery systems and defer significant transmission and distribution projects. Peak requirements have been met by distributed generation in a variety of utility settings. Project costs are now being collected more realistically, enabling distributed generation planning and preliminary product development.

With supporting cost information and analyses, this report presents twenty-four actual cases where distributed generation was installed by the utility. More specifically, the report provides planning, installation and operational background discussion about each case to help utility planning staff apply the information to their own project evaluations. In addition, the report presents cost guidelines developed from the case study information for evaluating future projects ranging from 1 MW to 10 MW output per site.

Report Overview

The remainder of this report is divided into the following sections:

- Section 2 profiles utility case studies and presents tabular summaries of key data.
- Section 3 presents guidelines for applying the data to DG project installation analysis.
- Section 4 presents guidelines for applying the data to analyzing operations and maintenance of DG projects.
- Section 5 discusses other data sources and planning considerations that can be used to supplement the information provided by the case studies.
- Section 6 discusses the environmental factors associated with DG project sites.
- Section 7 provides recommendations for utilities considering a distributed generation project.
- Detailed case data are presented in the Appendices.

2
CASE STUDIES

Basis for Selecting Cases

The following selection criteria served as the basis for this study:

- generators were to be at least 1 MW and no greater than 10 MW
- generators were to be for electric generation only (no combined heat and power projects)
- generators were to be utility owned and operated

While DG projects/options outside this scope can certainly be viable, these selection criteria were established to keep the focus on utilities' use of DG. Co-gen projects were excluded because significant differences in the costing and other analyses would have added complexity and weakened any general conclusions.

Selection of Cases

Seventy-five utilities (where there was early indication of distributed generation use) were initially approached. Twenty-four utilities stepped forward with information about their distributed generation projects and offered to serve as case examples. Initial telephone contact was made with all candidate utilities and a formal data request[1] was provided to receptive respondents. Follow-up contacts were made to move along responses, to clarify information requested and responses received, and to address additional questions. A map providing a basic picture of case locations is presented in Figure 2-1.

The participating utilities represented three separate types of corporate governance and ownership, as shown in Table 2-1.

The majority of these projects were installed between 1998 and 2001; with the earliest project installed in 1956. In some form, all projects improve service reliability at the customer, distribution system, or transmission system level. Seventeen projects installed new equipment and the remainder installed used, or a mix of new and used equipment.

[1] This data request and the various responses received are provided in the Appendices.

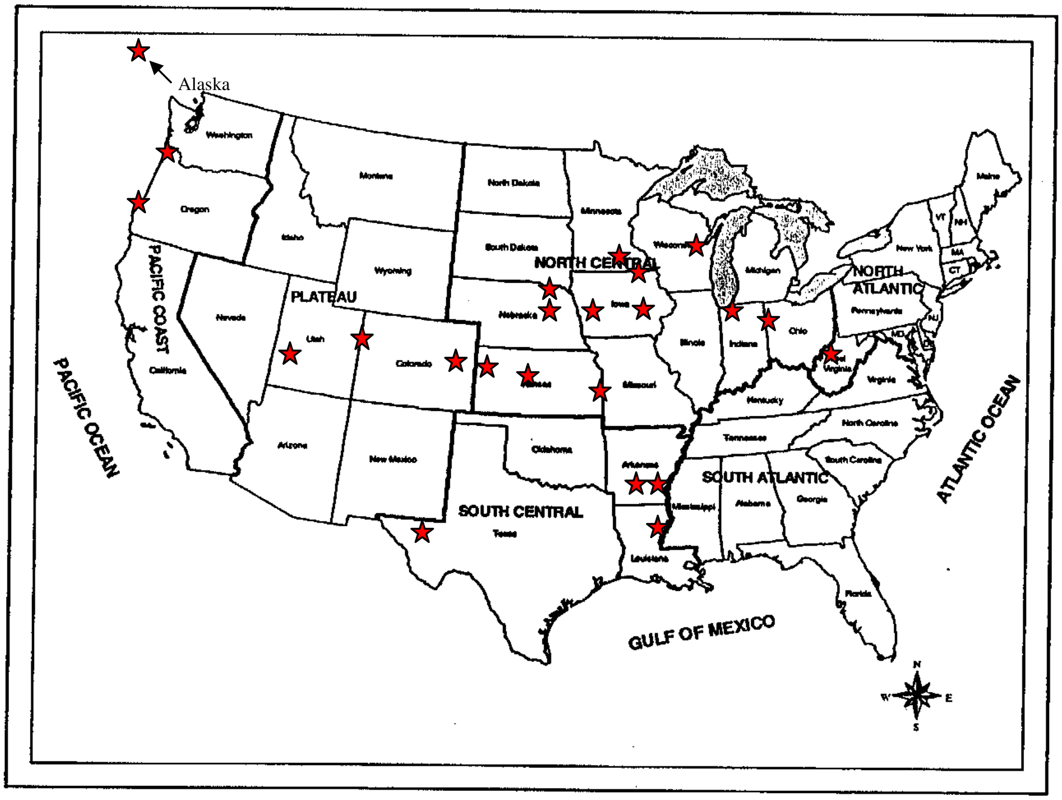


Figure 2-1
Locations of DG Case Studies

Summary of Responses

The generator and site characteristics of the aggregate cases are shown in Table 2-2. Most of the distributed generators in the cases are diesel-fueled engines with only a few fueled by natural gas. All are reciprocating engines with the exception of one combustion turbine. Table 2-3 summarizes the case responses.

Table 2-4 summarizes the cases, listing the utilities in alphabetical order. The table portrays the key characteristics of the DG projects. Table 2-4 also shows that diesel-fueled reciprocating engines are commonly used in a variety of applications. The most common units range in size from 1.8 MW to 2 MW prime outputs. These are the largest, easily transportable units that can be manufactured as a single integrated engine-generator set.

Table 2-1
Study Participants by Ownership Structure

Electric Cooperatives	Public Power	Investor Owned Utilities
Anonymous Utility A	Anonymous Utility B	Anonymous Utility G
Central Virginia Electric Cooperative	Anonymous Utility C	Anonymous Utility H
East Mississippi Electric Power Association (3 sites)	Anonymous Utility D	
South Plains Electric Cooperative	Anonymous Utility E	
	Anonymous Utility F	
	City of Fennimore	
	City of Garnett	
	City of Iola	
	City of New Knoxville	
	City of Owensville	
	City of Rock Falls	
	City of St. George	
	City of Wrangell	
	Grant County Public Utility District	
	Waverly Power & Light	
	Arkansas River Power Authority	

Table 2-2
Summary of Generators Used by Case Participants

Generator Types	Total Units	Total Net Capacity	Fuel Type
1 case used combustion turbines	1	4.2 MW	Natural gas
23 cases used internal combustion engines	6	15 MW	Natural gas
Note: two sites were dual fuel (diesel and/or natural gas)	93	183 MW	Diesel

Table 2-3
Summary of Case Responses[2]

Number of Units	<3 Gensets	3-5 Gensets	>5 Gensets
Utilities Reporting	*11*	*9*	*5*
Genset Size	<1.5 kW	1.5 kW-3 kW	>3 kW
Utilities Reporting	*4*	*17*	*4*
Total (Prime) Capacity	<4 MW	4 MW-8 MW	>8 MW
Utilities Reporting	*9*	*5*	*10*
Fuel Type	Diesel	Natural Gas	Diesel & NG
Utilities Reporting	*20*	*2*	*2*
Generator Voltage	<2.5 kV	2.6 kV-7.5 kV	>7.5 kV
Utilities Reporting	*6*	*11*	*6*
Interconnection Voltage	<5 kV	5 kV-13 kV	>13.1 kV
Utilities Reporting	*9*	*7*	*6*
Installation Date	<1993	1993-1998	>1998
Utilities Reporting	*1*	*4*	*19*
Installed Condition	New	Used	Mixed
Utilities Reporting	*17*	*6*	*1*

[2] "Utilities reporting" may not add to 24 as some cases involved multiple generator sets of different characteristics.

Table 2-4
Overview of Cases

Utility	Utility Type	Location (State)	Primary Purpose	# of Gensets	Unit Prime Rating (MW)	Site Capacity (MW)	Installation Dates	Installed New or Used	Avg. Warrantee (Years)	Generator Voltage (kV)	Intercon. Voltage (kV)	Fuel Type	Operated <200 hr./year	Est. Cost of Project	Est. Cost per kW	Maintenance
Anonymous Utility A	C	MI	Bk	3	.9-1.25	3.4	2000	Mx	1	0.48	14.4	D	Y	$ 1,900,000	$ 559	Out
Anonymous Utility B	PP	IA	PS	2	1.825	3.65	2000	New	2	4.16	2.4	D	Y	$ 1,532,000	$ 420	Out
Anonymous Utility C	PP	IA	PS	3	2	6	1999	New	10	12.5	12.5	D	Y	$ 1,650,000	$ 275	Mx
Anonymous Utility D	PP	OH	Bk	1	1.825	1.825	2000	New	10	4.16	4.16	D	Y	$ 707,000	$ 387	Out
Anonymous Utility E	PP	KS	Mx	1	1.36	1.36	1998	Used	1	2.4	13.8	DNG	Y	$ 435,000	$ 320	In
Anonymous Utility F	PP	IA	PS	10	1.95-6.2	24.35	1956-2002	New	5 to 10	2.4	12.5	DNG	Y	not available	n/a	Mx
Anonymous Utility G	IOU	OR	Bk	4	1.6	6.4	2001	New	n/a	12.7	12.7	D	Y	not available	n/a	Out
Anonymous Utility H	IOU	WI	Mx	1	1.825	1.825	1998-2001	New	n/a	n/a	n/a	D	Y	not available	n/a	Out
Central Virginia EC	C	VA	Mx	1	2	2	1999	New	n/a	0.48	12.5-24.9	D	N	$ 506,000	$ 253	Out
City of Fennimore	PP	WI	Mx	3	1.825	5.475	2000	New	n/a	4.16	4.16	D	Y	$ 2,059,000	$ 376	In
City of Garnett	PP	KS	Mx	1	2.5	2.5	1999	Used	3	4.16	4.16	D	Y	$ 862,000	$ 345	In
City of Iola	PP	KS	PS	2	5	10	1997, 1999	New	3	12.5	12.5	NG	N	$ 4,500,000	$ 450	In
City of New Knoxville	PP	OH	PS	1	1	1	1999	Used	0	0.48	12.5	D	Y	$ 267,000	$ 267	Out
City of Owensville	PP	MO	PS	2	1.825	3.65	2000	New	5	4.16	34.5	D	N	$ 1,315,000	$ 360	In
City of Rock Falls	PP	IL	PS	5	1.825	9.125	2001	New	5	12	34.5	D	Y	$ 865,000	$ 95	Out
City of St. George	PP	UT	PS	2	7	14	1987	Used	0	6.9	n/a	D	N	$ 5,500,000	$ 393	In
City of Wrangell	PP	AK	Bk	3	2	6	2001	Used	0	n/a	n/a	D	Y/N	$ 1,820,000	$ 303	In
East Mississippi I -NAS	C	MS	Bk	5	1.825	9.125	1998	New	10	4.16	4.16	D	N	$ 3,500,000	$ 384	Out
East Mississippi II -Canton	C	MS	PS	5	2	10	2002	New	10	4.16	4.16	D	N	$ 3,473,000	$ 347	Out
East Mississippi III -Henderson (D)	C	MS	PS	5	1.825	9.125	2001	New	10	4.16	4.16	D	N	$ 3,391,000	$ 372	Out
East Mississippi III -Henderson (NG)	C	MS	PS	3	1.35	4.05	2001	New	10	4.16	4.16	NG	N	$ 2,157,000	$ 533	Out
Grant County PUD	PP	WA	Mx	20	1.6	32	2000	New	n/a	13.8	115.0	D	Y	$ 25,265,000	$ 790	Out
South Plains EC	C	TX	PS	1	1.6	1.6	2001	Used	0	0.48	12.5	D	Y	$ 262,000	$ 164	Out
Waverly Power & Light	PP	IA	PS	6	2	12	2000	New	5	12.5	12.5	D	Y	$ 3,997,000	$ 333	Out
Arkansas River Power Authority	PP	CO	PS	1	4.2	4.2	2001	New	1	4.16	4.16	NG	N	$ 2,295,000	$ 546	Mx

n/a - information either not available at time of writing or of nsufficient quality
UTILITY TYPE: C - Coop, PP - Public Power, IOU - Investor Owned;
PRIMARY PURPOSE: PS - Peak Shave, Bk - Backup, Mx - Mixed ;
FUEL TYPE: D - Diesel Only, NG - Natural Gas Only, DNG - Diesel and NG; MAINTENANCE: In - Fully Insourced, Out - Fully Outsourced, Mx - Mixed

Case Study Profiles: Summary Discussion by Case

Condensed profiles of each case study are provided in the following summaries. The survey responses were the primary source of information for profiles, supplemented on occasion by additional sources (e.g. utility websites). Case profiles of utilities wishing to remain unnamed are presented as Anonymous Utility A, Anonymous Utility B, and so on. The information in parentheses following the utility names describes their regional location, form of governance and DG interconnection location.

The detailed case responses are included in the Appendix. A general review of the case profiles provides insight into some of the similar and different circumstances faced by electric utilities. These cases may help an interested utility advance its consideration of DG by bringing to light issues that bear consideration. Also many cases provide names of organizations currently using DG, who an interested utility may wish to follow-up directly.

Anonymous Utility A (Midwest, Cooperative, Feeder-Line)

Utility A of Michigan uses several miles of marine cable to serve a sizeable number of consumers on an island. After experiencing frequent outages, the utility started looking at options to improve service to its members. After consideration, the utility decided to install a diesel engine to provide backup generation during electric outages and, on occasion, to reduce summer peak power flow through the underwater cable.

The utility had a contractor install the DG unit and construct a building to protect the unit from snow and sleet. Construction costs were higher than anticipated because of complications with working on an island with rough terrain. Maintenance of the unit has been outsourced to an experienced technician living on the island.

The noise when the generator runs was not of significant concern as the islanders were more interested in improved reliability. As electric load continues to grow on the island, the utility will consider installing additional generators.

Anonymous Utility B (Midwest, Municipal, Power Plant)

Utility B is a municipal electric utility in Iowa providing service to about 1,000 consumers. The terms of its power purchasing agreement required the utility to install distributed generation units. The primary DG purpose is to reduce peak demand during all billing cycles.

In 2000, the utility replaced two older units with two 1,825 kW diesel reciprocating engines. The utility had to revise its current air emission permit to meet the specifications for the new units. The permitting process took approximately 30 days.

With the exception of some mechanical difficulty integrating the new generators and the old switchgear, the installation went smoothly because employees were already familiar with such equipment. After the contractor successfully installed and tested the units, the utility decided to add additional insulation inside its power plant to decrease noise levels.

The utility plans to operate the units less than 200 hours per year, and it starts the units manually upon receiving telephone notice from its wholesale power supplier. Maintenance, meanwhile, is outsourced to Caterpillar under a five-year maintenance contract.

Anonymous Utility C (Midwest, Municipal, Power Plant)

Utility C is a municipal electric utility in Iowa that wanted to improve reliability and reduce expenses. In addition, the utility wanted to find a short-term solution to moderate load growth. Though the utility did not perform any feasibility studies, it did visit nearby municipalities to seek information on distributed generation. The utility negotiated a revised contract with its power provider to accommodate DG installation.

The turnkey project included the installation of three new diesel engines in the existing power plant. The utility purchased a 10-year warranty and uses utility employees and contractors to maintain the units.

The utility and its power supplier jointly decide when to operate the units depending on each of the system's peaks (the utility is summer peaking and the power supplier winter peaking).

Anonymous Utility D (Midwest, Municipal, Power Plant)

Utility D of Ohio is a municipal electric utility that installed one new 1,825-kW diesel engine in 2000. Overall, the installation went smoothly, and the utility is receiving credits from its power supplier for this installation.

The unit is primarily operated during power outages and during peak summer periods. The unit is manually started when the power supplier notifies the utility during peak periods. Meanwhile, the utility decides independently whether to operate the unit during outage situations.

The unit has a 10-year warranty, and the utility has a five-year contract to outsource maintenance at a cost of about $5,500 per year. The utility has no current plans to install additional units.

Anonymous Utility E (Midwest, Municipal, Power Plant)

Utility E in Kansas is a municipality that owns its own power plant. The utility was looking to replace one of its old generating engines with a newer engine fueled by diesel and natural gas. Due to negative load growth, the utility's goal was to find a used engine at a reduced price so electric rates could be controlled.

With specifications for the replacement unit compatible with the existing (older) unit, the utility found an acceptable generator and proceeded with installation. Installation went fine, with only minor revisions needed to the existing generator foundation.

The utility uses its generators for managing peak demand and backup during power outages. The utility's chief operator monitors its system load curves to determine when to operate the equipment, which is started manually.

Anonymous Utility F (Midwest, Municipal, Power Plant)

Utility F of Iowa is a municipal serving about 3,500 consumers. The utility decided to have enough backup generation to serve the entire city in times of power outages. In addition, a primary purpose of its DG is for managing peak demand during summer months.

The utility has a total of 10 distributed generation units located in its power plant building. The utility purchases new generation units with a five- or 10-year warranty. The utility has its trained diesel maintenance employees perform routine maintenance, but it outsources engine overhauls to contractors.

The utility manually starts the generator when it receives a telephone call from its power supplier. To accommodate future load growth, the utility plans to install additional new distributed generation units.

Anonymous Utility G (West, IOU, Customer Site)

Utility G in the Northwest has a subsidiary providing backup generation to a large banking (data warehousing) facility. The utility's resource study identified opportunities to offer distributed generation programs to large consumers. To that end, the utility has four Caterpillar diesel-powered generator units, which are parallel connected and provide 100% backup generation. The units were transported to the site by rail.

The generation units are located directly inside the customer site. Sound is not an issue because of the facility's extremely solid construction. The utility is ultimately responsible for maintenance but outsources the work on an annual contract. Available for peak shaving, the utility's wholesale power group makes buying decisions, and (at the right price point) a trader informs a dispatcher to remotely start the units.

The utility has no plans to add generators to the site at this time, but space is available for eight more units should the need arise.

Anonymous Utility H (Midwest, IOU, Customer Site)

Utility H started its DG program during the Y2K concerns related to potential electric supply interruptions, and it continues under a general service reliability improvement program. Consumers agree to provide space for these permanently installed, diesel engine units at their sites.

The units are dispatched by the utility for grid support and power supply reasons, but the generators can provide isolated backup service to individual consumers during power delivery system interruptions. The consumers pay a fixed service charge to the utility for the service reliability improvement, which is derived from having the backup generation on-site. The utility assumes all costs of ownership and operation.

The utility test runs each unit at least monthly and has identified problems with batteries and control modules that require occasional repair or replacement. The units only operate about 20 hours per year for extreme peak shaving or backup purposes.

Central Virginia Electric Cooperative (East, Cooperative, Substation)

Central Virginia Electric Cooperative (CVEC) of Virginia installed DG to improve distribution system reliability to a developing subdivision. CVEC created the wholly owned subsidiary, Central Virginia Service, Inc., to supply distributed generation services and systems. (Electric distribution cooperatives may find this strategy necessary because they generally have wholesale power agreements that preclude them from supplying any portion of their own power.)

CVEC's service to the development was experiencing reliability problems and the area homeowners association was petitioning for a transfer of service. CVEC had exhausted all reasonable efforts to improve reliability with its existing facilities. The distribution line right-of-way (ROW) crossed heavily wooded areas that are not easily accessible, and the mature timber on the ROW continued to cause outages. The capacity of the distribution system was adequate to the supply load.

CVEC considered three alternatives to improve service to the area: *Alternative #1* was to build a transmission line tap and construct a substation at the edge of the service area at an estimated cost of $1.8 million; *Alternative #2* was to convert the area to 25-kV distribution and establish a secondary feed to the development at an estimated cost of $400,000; *Alternative #3* was to install local generation using a 2,000-kW diesel generator connected to the grid with a pad-mounted distribution transformer at an estimated cost of $525,000.

The DG option was chosen in part because the wholesale power supplier provides a $16/kW/month incentive for peak shaving operations. CVEC already had five years of experience with diesel generators used for peak shaving at one of the cooperative's substations. The cooperative also had a rate in place that gave 50% of the savings ($8/kW) to any customer that had generation and would operate it on the monthly coincident peak. The CVEC subsidiary proposed that if the customer would release its monthly load management credits of $8/kW/month to the subsidiary, it would install, operate and maintain the generator set. Using an isolation switch controlled from the generator, the subdivision could be isolated from the utility system in the event of a power outage and the entire subdivision could be provided with standby generation with one large 2,000-kW generator.

At the distribution utility grid level, the reliability of service to the subdivision was markedly improved. CVEC also avoided investment in a distribution reinforcement project solely to improve reliability. At the wholesale power level, CVEC saw a reduction in monthly power bills on the interruptible credit. The CVEC subsidiary also earns a margin on the installation. The project was operational beginning in November 1999.

CVEC's subsidiary has a total of 21 MW in 13 diesel generator units operating under similar circumstances. An $8 per kW credit goes to the subsidiary each month to cover the debt service and to operate and maintain the generator. The cooperative also enjoys an annual benefit of $8/kW in reduced wholesale power costs. Although the annual cost is $781,000, the annual wholesale power cost reduction to the cooperative is $2,016,000, a significant savings.

The project life is expected to end when the cooperative's wholesale power supply contract expires in January 2005. The useful life of the generator is much greater. Ceva Energy (a CVEC subsidiary) provided turnkey implementation of the project. The generator dealer provided the generator, fueling and switchgear according to specifications. CVEC engineering did the concrete pad layout, SCADA (Supervisory Control And Data Acquisition) interface and isolation switch control design working with the switch manufacturer, and procured a contractor for installation. With Ceva Energy having experience managing installation of similar projects for large CVEC members, the first generator installation required one year from authorization to being placed into service. Using the same design for all others, subsequent installations required six months. In respect to permitting, emissions permits for all units took about six to eight weeks, with zoning taking about three months (necessary for just the first unit).

The actual maintenance costs are $71,233 per year for the entire program's 13 units. In general, the units are expected to operate approximately 120 hours per year. A maintenance agreement is in place with the local Caterpillar dealer; it includes quarterly fluid testing and changing, and filter changes. An extended warranty covers major parts of the generator set for five years or 2,500 hours, whichever is first. The generators are also test run and inspected, and the meters are read at least once a month by CVEC. The units are monitored but not remotely controlled by SCADA. The units are also manned at the one-hour monthly wholesale demand peak to ensure operation at peak.

City of Fennimore (Midwest, Municipal, Power Plant)

The City of Fennimore, Wisconsin, operates its own electric utility plant and distribution lines. In 2000, the utility installed three new 1,825-kW diesel-fueled generation units to avoid demand charges. The units are mainly operated to reduce peak demand during the summer and to manage power outages.

The units are located in an existing facility owned by the utility. A contractor provided a turnkey solution for installing the units, which included updating the switchgear to ensure proper operation. Existing personnel trained in diesel mechanics maintain the three units at a minimal annual cost.

The utility's power supplier monitors load curves and notifies the utility when to manually start the units. In the next five to 10 years, the utility plans to add another unit, replacing an existing, old generator.

City of Garnett (Midwest, Municipal, Power Plant)

The City of Garnett, Kansas, belongs to a power pool that requires 15% excess capacity. The utility installed one DG unit to meet its capacity requirements. The municipal utility operates the unit primarily during summer months to reduce peak demand and, occasionally, as base load during power outages.

The utility chose a contractor who provided turnkey service for the installation, which included an expansion of an existing building that also will provide space for a future unit. The rebuilt generator came with a three-year or 2,000-hour warranty.

The utility plant superintendent monitors load curves and decides when to manually start the generation unit. With the addition of the DG unit, the utility anticipates having enough capacity for the next 10 years.

City of Iola (Midwest, Municipal, Power Plant)

The City of Iola, Kansas, operates its own electric utility. The utility's decision to install DG resulted from its wholesale power supplier's offer of a rate incentive, as well as the utility's desire for additional generation control. To this end, the utility decided to install one unit in 1997 and another in 1999. The utility purchased new units that included a three-year warranty for the 1997 unit and a one-year warranty for the 1999 unit. The two units are fueled by natural gas.

A contractor with a turnkey contract performed the installation, and existing personnel perform maintenance functions. The utility superintendent tracks load curves to determine when to start the generation units. At this time, the utility has no plans to install additional DG units.

City of New Knoxville (Midwest, Public Power, Power Plant)

The city (Village) of New Knoxville, Ohio, is a municipal utility interested in managing peak demand, and in 1999 it installed a 1-MW diesel unit. The utility installed the DG unit near the edge of town, isolated from the community. Prior to installation, air permits and site preparation relating to a generator foundation were needed. No sound attenuation was needed because the generator was isolated from the community. Switchgear was installed for generator connection to the system. Utility personnel installed the engine-generator unit and a contractor installed the switchgear.

Generator operation is determined by New Knoxville's power supplier, which also provides service to 87 other municipalities. The generator is started manually, but it does have remote start capability. New Knoxville is contemplating additional units for the future, if justified. Presently a 69-kV transmission upgrade appears more cost effective than a 1.8-MW installation.

City of Owensville (South, Municipal, Power Plant)

The City of Owensville, Missouri, operates its own electric power production plant serving about 1,500 consumers. The utility power plant has been in operation since 1938. To meet a growing customer base, the utility installed two new 1,825-kW diesel-operated reciprocating engines with five-year warranties. The units are mainly operated June through October, and their primary purpose is to manage peak demand.

The installation was turnkey, and the utility's engineering firm secured the air emission permit. Experienced internal personnel maintain the generators with a budget of about $1,000 per engine per year.

The utility manually starts the diesel engines when it receives telephone notification from its power supplier.

City of Rock Falls (Midwest, Municipal, Power Plant)

The City of Rock Falls, Illinois, operates its own electric utility serving about 5,000 consumers. The utility's power supplier performed a System Reliability Study and determined that installing DG at its municipal customer locations would be more cost effective than upgrading an existing transmission line. Rock Falls DG units are only operated during summer months to manage summer peak demand. The utility receives capacity credits based on the size of the units.

In 2001, the utility installed five 1,825-kW units with five-year warranties near its existing power plant. The installation took 12 months to complete after approval was granted for the project. The air emission permit took six months to secure. Installation consisted of new concrete foundations, the units, and a new building to decrease noise levels and improve aesthetics. Maintenance activities are outsourced on a year-to-year contract at an approximate cost of $2,500 per year per engine.

The utility receives telephone notification from its statewide organization to operate the units. The units are remotely started and shutdown. At this time the utility does not have any plans to install additional generators.

City of St. George (West, Municipal, Power Plant)

The City of St. George, Utah, owns and operates its own power generation plant. St. George has a 7% annual load growth and is primarily a community for retirement age citizens. The utilities decision to install DG was based on a need to provide backup generation (for when a federal hydro plant is offline) and a desire for more generation control. Purchased used from a nearby utility, the two 7,000-kW diesel DG units are primarily used for peak shaving during the summer and winter peaking periods.

The units are located in an existing power plant near the city's main substation. No additional property was purchased for the generators, but the city did construct a building to protect the units from excessive heat and sunlight. Utility employees, already trained in diesel engines, handle maintenance.

The utility operator monitors load curves and decides when to buy and sell electricity, starting the generator remotely. The city is exploring the possibility of converting the generator from diesel to natural gas to improve air quality and reduce operating expenses.

City of Wrangell (North, Municipal, Power Plant)

The City of Wrangell, Alaska, operates its own electric utility and is primarily served by a hydro facility with limited capacity. In addition, Wrangell is located on an island that is heavily wooded and subject to prolonged power outages. The marine cable serving the utility is also prone to potential damage from ice and boat anchors. In order to provide improved service to island consumers, the state of Alaska required the utility to install sufficient generation to provide service during power outages. The utility installed three diesel-operated reciprocating engines that are operated during power outages and scheduled maintenance of the hydro facility.

The utility installs, operates and maintains its generating units using its own employees, who have extensive experience with diesel generation units. In order to reduce capital expenditures, the utility usually purchases used generation units. The City of Wrangell does not have any plans to install additional units because it has adequate capacity for its current needs and expects little growth.

East Mississippi Electric Power Association (I) (South, Cooperative, Substation)

East Mississippi Electric Power Association (EMEPA) of Mississippi retained its largest customer, the Naval Air Station Base in Meridian, by using multiple diesel generator sets. This project permanently deferred a $5.2 million transmission line, improved reliability and provided tangible financial benefits to the Naval Air Station (NAS), the wholesale supplier and EMEPA itself.

In the mid-1990s, the U.S. Congress authorized a review of possible military base closures by the Base Closure and Realignment Commission (BRAC). EMEPA was concerned, as NAS-Meridian was on the initial closure list, and a base closure was estimated to affect 30% of the local economy. NAS-Meridian was also served by a 20-mile-long, 46-kV radial transmission line, which had an unacceptable extended outage record and marginal voltage conditions in serving the base's 8,500-kW peak load.

The EMEPA service area is composed of three non-contiguous areas. EMEPA's wholesale power suppliers are TVA for the NAS-Meridian base, as well as Mississippi Power and the Southeastern Power Administration for other areas. The NAS-Meridian base is located in a portion of Mississippi that has no high-capacity transmission system, and it also lacks interconnections between the three power suppliers. If the transmission system to the NAS-Meridian base could be reinforced, TVA would need to extend a 161-kV line radially and parallel with EMEPA's existing 20-mile line to address reliability and voltage regulation deficiencies on the EMEPA transmission line.

EMEPA decided on distributed generation because their largest customer could be lost and the local economy devastated if the BRAC process resulted in closing NAS-Meridian. The utility was also concerned because it had one unreliable, 46-kV transmission line and another 161-kV transmission line planned for the same right-of-way corridor.

After analyzing several options, EMEPA selected to develop a 46-kV to 4.16-kV substation near the NAS base. The substation was equipped with five Caterpillar Model 3516, 1825-kW diesel generators, and the TVA 161-kV line was deferred. After negotiations between TVA and EMEPA, TVA agreed to develop, own and operate the upgraded NAS-2 Substation.

The efficacy of this approach was demonstrated within three months of project completion. Two tornadoes and an ice storm severely damaged the 46-kV transmission line and could have done the same to a TVA transmission line on the same corridor. The NAS-Meridian base remained in service through this severe weather by running the generator units at the NAS-2 Substation.

EMEPA proudly points out that TVA, NAS-Meridian and EMEPA all were winners in this project. For NAS-Meridian, it improved infrastructure, increased reliability, improved efficiencies and maintained total energy costs. For TVA, it improved voltage support, secured a large customer, added peaking capacity and reduced capital expenditures. And for EMEPA (and the community) it resulted in a long-term contract, reduced outage exposure, improved voltage support, additional infrastructure margins, basic ordering agreement and a bolstered economy.

EMEPA completed a preliminary design of the NAS-2 Substation prior to negotiations with TVA. TVA further refined the design and completed the project. TVA monitors and operates the project out of TVA's Chattanooga Control Center via SCADA. EMEPA is also authorized to manually start and run the generator units.

The normal operation of the generators is to bring them on line when TVA calls for an interruptible load shed, or run them to sell into the system, or run them as backup for a transmission outage. The units have black-start capability. In "grid operation mode," the units are run at full capacity. In "load following mode," the units serve only the NAS base. When the grid is connected, the generators deliver a 10% voltage improvement to the 46-kV transmission system.

East Mississippi Electric Power Association (II) (South, Cooperative, Power Plant)

East Mississippi Electric Power Association also reported on a project for Canton Municipal Utilities that included installing five 2000-kW DG units to reduce peak demand. The stand-alone peaking facility provides service to five municipalities. The units are monitored from the Henderson Generation Plant and operated 80% of the time during the summer months.

The project required a new air emission permit and a new building was constructed to protect the environment from any spillage. The utility decided to outsource the maintenance to a nearby Caterpillar dealer at a cost of approximately $40,000 per year. For the future, the utility plans to install additional natural gas DG units as load dictates.

East Mississippi Electric Power Association (III) (South, Cooperative, Power Plant)

East Mississippi Electric Power Association also reported on a Greenwood Utility municipal group strategy to add additional peaking capacity at the Henderson Generation Plant as insurance against high market pricing. The two-phase project included installing five 2,000-kW diesel and three 1,350-kW natural gas units. The project's primary purpose is to manage peak demand, and the units are operated 80% of the time during summer months.

The utility had to add 4 feet of fill to protect the generator equipment from a flood plain. Also, a building was constructed to protect the units from weather and to provide sound attenuation. No noise related conditional use permits were required because the utility installed a silencer in the exhaust system.

The utility purchased new engine-generator units that included a 10-year warranty. Maintenance is outsourced at a cost of about $40,000 per year. The utility has short-term plans to increase capacity and improve capacity shortage problems.

Grant County Public Utility District (West, Public Power, Substation)

The Grant County Public Utility District of Washington described a mobile generation installation it completed in 2001. The installation included 20 1,600-kW diesel-fueled units connected at 13.8 kV to an existing 115-kV to 13.8-kV distribution substation.

The primary objective of this project was to cover expected power supply shortages during 2001, which resulted from low water supplies for hydro plants and regional power supply shortages. The project can provide backup service to the distribution substation during transmission supply interruptions or a substation transformer failure.

The district was able to site this amount of generation at one location by securing a one-year temporary emissions license based on the water shortage. The one-year license was necessary because the project was large enough to require a full EPA review for a permanent license, which would have taken more time than the project schedule allowed. The district is currently pursuing a long-term license to extend the project several years.

The district completed the project in eight weeks using leased generation equipment. The project has been operating on a one-year temporary license, which expired July 2002, and is performing well to date. The project has had no failures. During 2002 the Washington Department of Ecology approved a new air quality permit to extend the projects operation.

South Plains Electric Cooperative (South, Cooperative, Main-Line)

South Plains Electric Cooperative (SPEC) is a rural electric utility serving about 35,500 consumers in south Texas. Though SPEC had a section of its service territory with minimal consumer growth, a large number of irrigation accounts provided a 30-MW increase in load during a 12-week period. Because of the low growth area, however, SPEC could not justify capital expenditures to meet current irrigation demands. In addition, several of the irrigation accounts were several miles from the substation, causing reduced quality of service. After evaluating several options, SPEC decided to locate a diesel reciprocating engine along a three-phase power line. The project's purpose was to manage peak demand while the irrigation accounts were operating, increase load factor and improve line voltage.

SPEC staff designed and installed the DG unit. Installation took approximately six months after the project was authorized. SPEC negotiated an agreement with one of their members to lease space for the trailer mounted DG unit. Because no members are located near the DG unit, SPEC did not install any sound attenuation barriers. The utility encountered only minor start-up problems. SPEC decided to outsource maintenance to trained area mechanics.

SPEC decides when to operate the DG unit by monitoring line voltage levels with its automated meter reading (AMR) system. The unit is started manually and shutdown remotely. SPEC is considering natural gas DG units because diesel fuel costs are high for the number of operating hours required.

Waverly Light & Power (Midwest, Municipal, Power Plant)

The City of Waverly, Iowa, has its own municipal electric utility serving 4,000 consumers. Generator studies indicated a need for additional capacity to serve its customer base, so the city installed six 1,825-kW diesel generators at its existing power plant. The diesel units are only used during the summer months for peak shaving.

The utility decided to construct a new building to house the diesel units to minimize noise level concerns, provide weather protection and provide acceptable appearance with a nearby residential development. The utility had to obtain an air emission permit from the Iowa Department of Natural Resources before the units could be installed. The biggest obstacle the utility faced was coordination of the installation with multiple contractors.

The utility purchased a five-year warranty on the new engines, and it decided to outsource maintenance at an average cost of about $5,800 per engine per year. MidAmerican Energy monitors the electric use patterns and informs the utility by telephone when to operate the units. Utility personnel start and shut off the diesel units manually.

Arkansas River Power Authority (West, Public Power, Power Plant)

Arkansas River Power Authority, of Colorado, provides electric service to seven municipalities. The utility's Integrated Resource Plan identified the need to install more capacity in order to improve customer service. Because buying power from the grid was extremely expensive, the utility opted to install its own (distributed) generation, which it uses to manage peak demand and provide base-load when gas prices are favorable.

The utility installed a 4,200-kW Solar Mercury 50 combustion turbine. The utility worked with Solar to install the unit as a prototype because the Solar Mercury 50 unit was not commercially available at the time of installation. The unit was purchased with a one-year warranty and a building for weather and sound protection. A 4-foot-thick slab was installed because of the high water table. The utility had minor installation and start-up problems because of the new product. At times when the temperature is cold, the utility has to pre-heat the gas to start the unit. Utility personnel perform routine maintenance, while more difficult maintenance functions are outsourced.

Arkansas River Power Authority and the Lamar Electric Cooperative jointly review gas prices and purchase one-month contracts when gas prices are low. The utility plans to add distributed generation as load growth increases.

3
GUIDE TO APPLICATION OF THE DATA

The utility responses provided project investment cost data for the following general categories:

- Engine-generator set acquisition costs
- Switchgear and interconnection equipment costs
- Engine-generator set enclosure costs
- Site development, installation and start-up costs
- Costs for engineering and project management

Engine-Generator Acquisition Costs

Table 3-1 presents a summary of diesel engine-generator set acquisition costs reported in the utility responses. The data shows that the 1.82 MW unit is the most commonly used size, because it is the largest skid-mounted engine-generator set that can be easily transported to a project site via truck. Multiple units are combined together in parallel for larger site applications. The cost per unit (and per kW) varies because different accessories were provided for each specific site, which were not detailed in the responses. The three highest numbers included a fast track schedule and other site work components, which makes these numbers not directly comparable to the other installations. A couple of projects involved used equipment that is not comparable to the installations using new equipment. The remaining 10 utilities experienced costs ranging from $119 to $227 per kW of prime capacity. The average cost of these 52 units is $205 per kW.

The Utility E, F, G, and H data are not listed in Table 3-1 because the unit acquisition data was not provided or the project scope was too different to be used for comparisons.

Switchgear and Interconnection Costs

A few responses provided itemized data for the switchgear and interconnection equipment associated with their projects. This data is summarized in Table 3-2.

Table 3-1
Summary of Diesel Genset Acquisition Costs

Utility	# of Gensets	Genset Size (MW prime)	Cost per Genset ($)	~Cost per kW ($)	Comments
Anonymous Utility A	3	.9-1.25	180,700	175	New
Anonymous Utility B	2	1.825	302,800	166	New
Anonymous Utility C	3	1.825	332,000	182	New
Anonymous Utility D	1	1.825	341,500	187	New
Central Virginia EC	10	2	408,000	204	New
City of Fennimore	3	1.825	260,900	143	New
City of Garnett	1	2.5	634,600	254	Includes site work
City of New Knoxville	1	1	200,000	200	Used
City of Owensville	2	1.825	600,000	329	Includes site work
City of Rock Falls	5	1.825	400,000	219	New
City of Wrangell	3	1.825	216,700	119	New
East Mississippi (Diesels)	15	1.825	414,600	227	New
Grant County PUD	20	1.6	780,000	488	Fast Track Installation
Waverly Power & Light	6	1.825	324,000	178	New
South Plains EC	1	1.6	192,000	120	Used

Table 3-2
Summary of Switchgear and Interconnection Costs

Utility	# of Genset s	Switchgear Cost ($)	Switchgear Cost/Genset ($)
Anonymous Utility A	3	243,700	81,200
Anonymous Utility B	2	117,300	58,700
Anonymous Utility C	3	386,000	128,700
Anonymous Utility D	1	41,700	41,700
Central Virginia EC	10	146,500	14,700
City of Fennimore	3	194,400	64,800
City of New Knoxville	1	15,000	15,000
City of Owensville	2	115,000	57,500
City of Rock Falls	5	175,000	35,000
City of Wrangell	3	510,000	170,000
East Mississippi (Diesels)	5	277,200	55,400
Waverly Power & Light	6	526,100	87,700
South Plains EC	1	20,000	20,000

The data shows that switchgear and interconnection equipment costs can vary significantly, from $14,700 to $170,000 per generator unit. Switchgear and associated equipment can include things like circuit breakers, step-up transformers, medium voltage interconnection cable, control devices and substation structures. The descriptive details were not included in the responses so the scope for these costs is not well-defined. The average switchgear and interconnection equipment cost is $61,500 per generator set.

Enclosures

Some of the utility responses indicated project enclosure costs while others had them included in site development or the unit acquisition costs. There were a few cases where projects did not have any enclosure costs because the owners took advantage of existing facilities by replacing previously retired equipment with new equipment. Table 3-3 presents a summary of the enclosure costs reported in the utility responses.

The data shown in Table 3-3 indicate that the enclosure costs can vary significantly due to the specific requirements of each site. The average cost for enclosures was $52,900 per generator unit.

Table 3-3
Summary of Enclosure Costs

Utility	# of Gensets	Enclosure Cost ($)	Enclosure Cost/Genset ($)	Comments
Anonymous Utility D	1	83,200	83,200	
City of Fennimore	3	78,100	26,000	
City of Garnett	1	170,400	170,400	Includes site work
City of Rock Falls	5	100,000	20,000	
City of Wrangell	3	43,000	14,300	
East Mississippi (Diesels)	5	405,300	81,100	
Waverly Power & Light	6	389,000	64,800	

Site Development, Installation and Start-Up Costs

Most utility responses provided some information about their project site development, installation and start-up costs as summarized in Table 3-4 These costs are presented in lump sum format because additional detail is not available on a consistent basis from the project records.

The data shown in Table 3-4 shows that the site development and installation costs can vary extensively from project to project, which is most likely due to cost accounting differences. The average of these costs per unit is $134,600.

Engineering and Project Management Costs

Engineering and project management costs were provided for about one-half of the projects. This information is presented in the following summary (Table 3-5).

The data shown in Table 3-5 shows that engineering and other overhead costs appear to vary extensively from project to project, which is most likely due to a combination of cost accounting differences and variations in project implementation methods. The average of these costs per unit is $30,900 and the average cost per project is $166,700.

Table 3-4
Summary of Site Development, Installation and Start-Up Costs

Utility	# of Gensets	Site, Etc, Costs ($)	Site, Etc, Costs/Genset($)
Anonymous Utility B	2	392,900	196,500
Anonymous Utility C	3	155,400	51,800
Anonymous Utility D	1	169,300	169,300
Central Virginia EC	10	436,100	43,600
City of Fennimore	3	853,800	284,600
City of New Knoxville	1	52,000	52,000
City of Owensville	2	185,000	92,500
City of Rock Falls	5	60,000	12,000
City of Wrangell	3	279,000	93,000
East Mississippi (Diesels)	15	3,463,200	230,900
Waverly Power & Light	6	902,800	150,500
South Plains EC	1	49,000	49,000

Guide for Estimating Diesel DG Project Costs

The extensive variation and apparent crossover of costs among the five general categories presented in the previous tables suggest that using the total project cost data as a whole may provide a better guide for developing budgetary project estimates.

The project case data was grouped by two fuel types: diesel and gas. Twenty-one case studies were diesel fueled and three were by gas, including two internal combustion engines and one combustion turbine. A limited analysis of the gas installations is made later in this section.

Four of the diesel responses lack either certain key data points or their project scopes were too different for direct comparison to the other cases. These cases and the actual concerns were:

- Utility F – insufficient key data points
- Utility H – insufficient key data points
- Utility E – this project was a modification of an existing site rather than a new site development or project addition
- Utility G – this project was an upgrade of an existing site rather than a new site development or project addition

Table 3-5
Summary of Engineering and Project Management Costs

Utility	# of Gensets	Related Costs ($)	Related Costs/Genset ($)
Anonymous Utility B	2	262,300	131,200
Anonymous Utility C	3	112,300	37,400
Anonymous Utility D	1	71,700	71,700
Central Virginia EC	10	16,100	1,600
City of Fennimore	3	150,000	50,000
City of Garnett	1	56,500	56,500
City of Rock Falls	5	130,000	26,000
City of Wrangell	3	278,000	92,700
Grant County PUD	20	355,600	17,800
Waverly Power & Light	6	234,800	39,100

A review of the diesel case study information shows the uniqueness of each project, which is one of the major observations of this study. Although there are many commonalities, it must be recognized that conditions and constraints of each project can have a major impact on the final cost of the project. Table 3-6 presents a summary of variables having an effect on project costs.

A number of the variables can be accounted for in order to reduce the scatter of the data. The following adjustments were made to the data that was provided by the utilities.

1. Date of installation: Costs were adjusted to the common basis of July 2002 by application of Handy – Whitman Indices of Public Utility Construction.

2. Type of Utility: Costs for rural electric cooperatives and privately owned utilities were adjusted to remove the sales taxes. No adjustments were made to municipal utility data due to their tax-free status.

3. Genset Warranty: Warranties ranged from 0 to 10 years. Through discussions with vendors we ascertained that the typical vendor adds 1% to the genset price for a one-year warranty, 2% for a five-year warranty, and 4% to the genset price for a ten-year warranty. We standardized the case study costs to the five-year level.

4. Used Equipment: A number of utilities installed equipment that was rebuilt or used. To account for this variable and preserve the ability to use the case study data we surveyed the internet during November, 2002 for current offerings of new and used equipment. We found that used equipment originally manufactured prior to 1994 was being offered for ~35% less than equivalent new equipment.

Table 3-6
DG Case Study Variables

State, Regional and Local Laws
Project size
Size (and number of gensets) used
Grid connection requirements
Permits required
Local cost of labor
State sales tax applicability
In house resources (availability and capabilities)
Technology used (combustion turbine or internal combustion engine)
Fuel type and grade
New (vs. used) equipment
Year of installation
Greenfield project, expansion, conversion or upgrade
Timeframe — temporary or permanent
Locale — proximity to neighbors, road access, air quality
Site — terrain (mountains, island), base/foundation, water table (underground storage)
Climate — temperature/humidity (weatherproof), wind,
Interconnection voltages
Remote monitoring
Financial considerations of utility (availability of funds)
Reason for DG installation
Schedule (level of urgency)

Analysis of Total Project Cost Data

Table 3-7 presents a summary of the adjusted case study data that was used in the following analysis.

Table 3-7
Summary of Case Study Costs Adjusted to July 2002, with a 5 Year Warranty

Utility	# of Gensets	Project Size (MW prime)	Cost of Gensets ($)	Other Costs ($)	Total Project Cost ($)
Anonymous Utility A	3	3.1	555,400	1,433,200	1,988,600
Anonymous Utility B	2	3.6	657,700	830,600	1,488,300
Anonymous Utility C	3	5.5	1,063,000	711,700	1,774,700
Anonymous Utility D	1	1.825	360,000	392,700	752,700
Central Virginia EC	10	18.2	4,233,100	604,500	4,837,600
City of Fennimore	3	5.5	841,400	1,372,400	2,213,800
City of Garnett	1	2.5	697,900	247,100	945,000
City of New Knoxville	1	1	222,100	73,000	295,100
City of Owensville	2	3.6	1,290,200	322,600	1,612,800
City of Rock Falls	5	9.1	1,945,600	452,800	2,398,400
City of Wrangell	3	5.5	992,200	1,079,800	2,072,000
East Mississippi (Canton)	5	9.1	1,908,500	1,298,300	3,206,800
East Mississippi (Henderson)	5	9.1	1,806,600	1,493,900	3,300,500
East Mississippi (Perry Davis)	5	9.1	2,159,200	1,468,800	3,628,000
Grant County PUD	20	32	15,175,500	9,401,800	24,577,300
South Plains EC	1	1.6	173,700	62,800	236,500
Waverly Power & Light	6	11	1,891,000	1,997,200	3,888,200
Total	*76*	*131.3*	*35,973,100*	*23,243,200*	*59,216,300*

Single Variable Regression Models

An overview of the range of project sizes and costs can be seen in Figure 3-1. A linear regression trend line was created and superimposed on the data. Figure 3-2 shows the same data with project cost normalized to a $/kW basis. Figures 3-1 and 3-2 both show one large kW data point at the right hand edge of the graph. This is the Grant County case where a large group of generators were installed in a hurry at one site for the expected California power supply shortages during 2001. The large project and extremely short installation time requirement combined to drive project costs up. The trend line without this case has a distinctively different look, as is indicated in Figure 3-3 (on the same scale as Figure 3-1) and replotted in Figure 3-4 with an expanded scale.

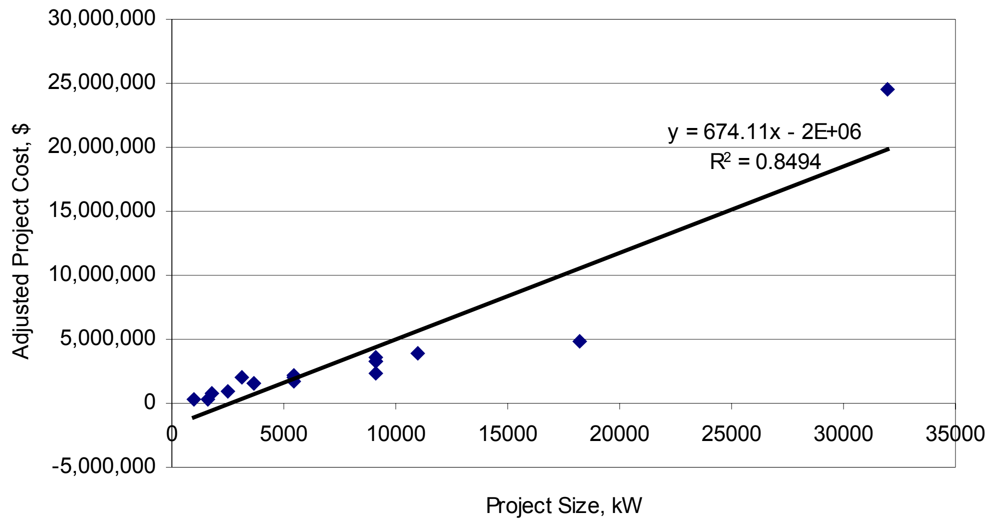


Figure 3-1
Total Project Cost Versus Project Size

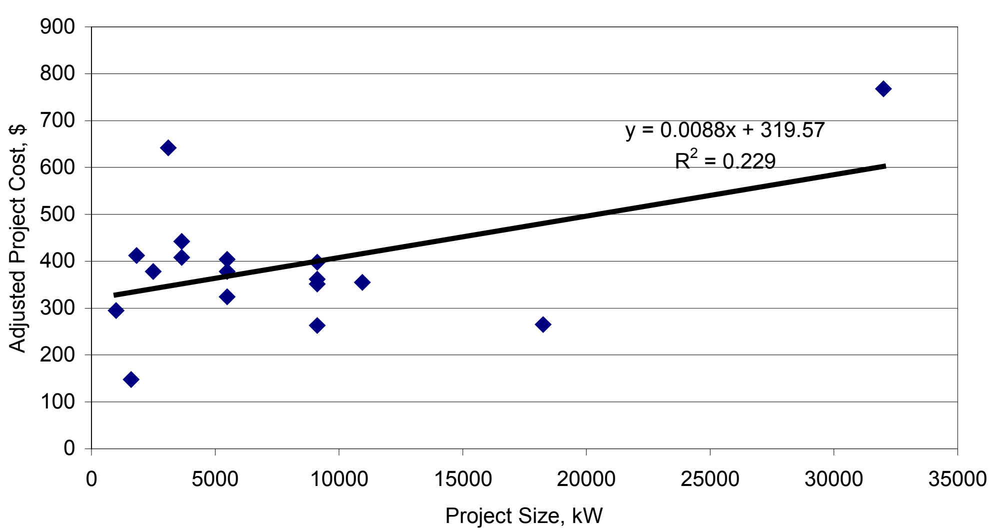


Figure 3-2
Total Project Cost Normalized to Cost/kW

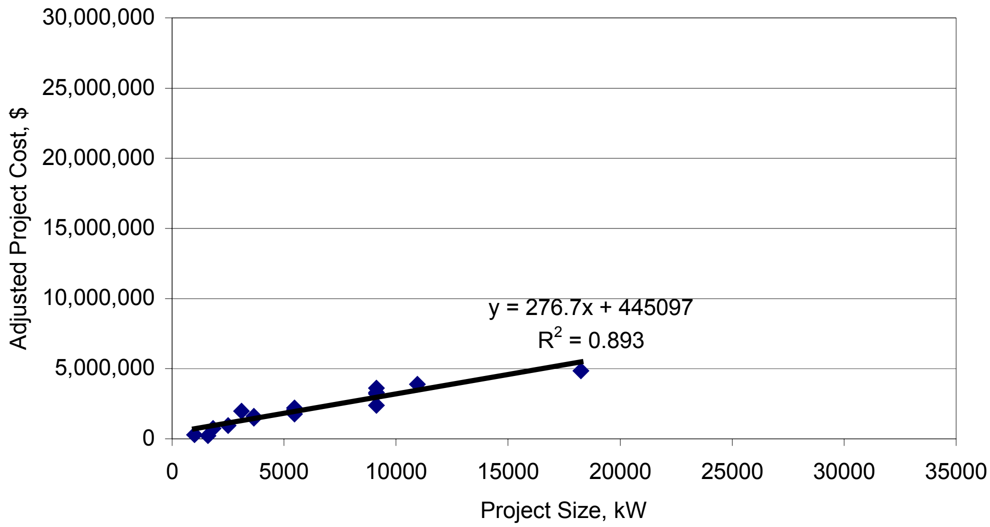
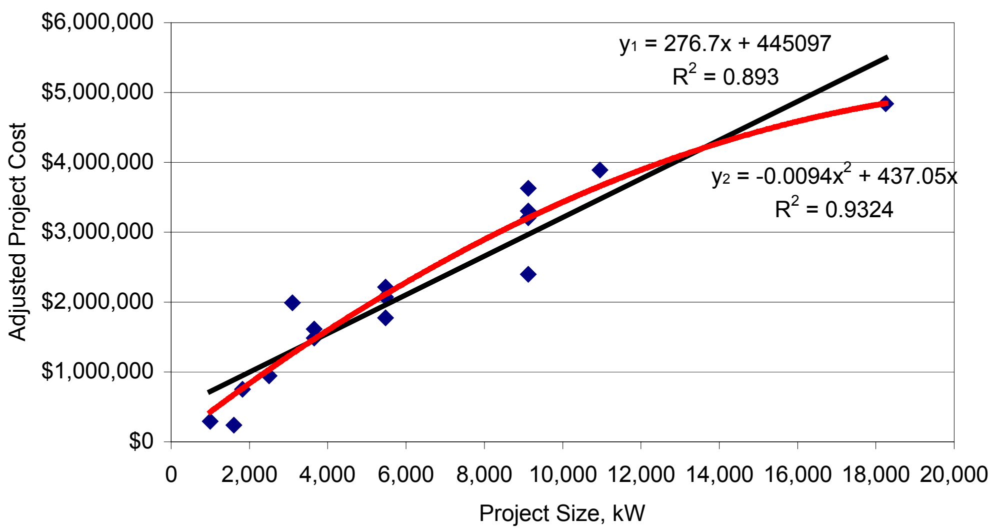


Figure 3-3
Total Project Cost without Grant County Case



$$Y_1 = (276.7)X + 445{,}097$$
$$Y_2 = (-0.0094)X^2 + (437.05)X$$

Where: Y_1, Y_2 = Total Project Cost, \$
X = Project Size, kW

Figure 3-4
Total Project Cost without Grant County Case – Expanded Scale

The results illustrated in Figure 3-1 through 3-4 show that unique project requirements can drive project costs significantly above and below normal levels. Grant County's total project cost of $768/kW was more than double the average value of all the other cases. There is one other data point showing an unusually high cost which apparently resulted from unique circumstances encountered at this site and caused the project's cost to be 45% higher than planned. These situations demonstrate that DG project estimators should carefully reflect on the list of variables in Table 3-6 as they pertain to the project/site under consideration.

Table 3-8 summarizes how well the Y_1 and Y_2 models predict the actual cost of the 16 cases listed in Table 3-7 (Grant County omitted).

Table 3-8
Single Variable Error Analysis

Utility	Y_1 Predicted Cost ($)	% Error	Y_2 Predicted Cost ($)	% Error
Anonymous Utility A	1,302,867	-34%	1,264,521	-36%
Anonymous Utility B	1,441,217	-3%	1,451,556	-2%
Anonymous Utility C	1,966,947	11%	2,119,425	19%
Anonymous Utility D	950,075	26%	766,308	2%
Central Virginia EC	5,481,037	13%	4,840,654	0%
City of Fennimore	1,966,947	-11%	2,119,425	-4%
City of Garnett	1,136,847	20%	1,033,875	9%
City of New Knoxville	721,797	145%	427,650	45%
City of Owensville	1,441,217	-11%	1,451,556	-10%
City of Rock Falls	2,963,067	24%	3,198,741	33%
City of Wrangell	1,966,947	-5%	2,119,425	2%
East Mississippi (Henderson)	2,963,067	-10%	3,198,741	-3%
Waverly Power & Light	3,488,797	-10%	3,670,150	-6%
South Plains EC	887,817	275%	675,216	186%
East Mississippi (Perry Davis)	2,963,067	-18%	3,198,741	-12%
East Mississippi (Canton)	2,963,067	-8%	3,198,741	0%
Average Error (Absolute Value)	-	*39%*	-	*23%*

The results shown in Table 3-8 indicate that both models have a few significant error values, which supports the suggestion that other variables beyond project size drive the project cost.

Two Variable Regression Model

The following two variable cost model was developed from the case data (without Grant County) where the total project size and number of units would be used together to predict the total project cost. The results of the 16 case study regression model is:

$$Y_3 = 376{,}000 + (373{,}000)X_1 + (79{,}000)(1{,}000X_2)$$

Where: Y_3 = Total Project cost, \$
X_1 = Number of units at the site
X_2 = Project Capacity, kW

The performance analysis for this model is summarized in Table 3-10.

Derived Cost Estimating Model for Project Components

The following cost components (Table 3-9) were derived from the itemized case study data (without Grant County).

Table 3-9
Cost Components

Component	Cost ($)
Genset	200/kW
Switchgear	40/kW
Enclosure	22,000 + 24/kW
Other	100,000 + 96/kW

The enclosure cost should only be added for projects that need a standalone building for the generating units. The other costs include site development, installation, start-up, engineering and project management.

The combined mathematical model for this approach is:

$$Y_4 = (336)X + 100{,}000$$
$$Enclosure = (24)X + 22{,}000$$

Where:		
	Y_4	= Total Project cost without enclosure, $
	$Y_4 + Enclosure$	= Total Project Cost with enclosure, $
	X	= Project Capacity, kW

Table 3-10 summarizes how well the Y_3 and Y_4 models predict the actually cost of the 16 cases listed in Table 3-7 (Grant County omitted).

Table 3-10
Two Variable Error Analysis

Utility	Y_3 Predicte d Cost ($)	% Error	Y_4 Predicted Cost ($)	% Error
Anonymous Utility A	1,730,900	-13%	1,141,600	-43%
Anonymous Utility B	1,397,400	-6%	1,326,400	-11%
Anonymous Utility C	1,920,500	8%	1,939,600	9%
Anonymous Utility D	884,175	17%	779,000	3%
Central Virginia EC	5,534,800	14%	6,215,200	28%
City of Fennimore	1,920,500	-13%	2,093,000	-5%
City of Garnett	937,500	-1%	1,022,000	8%
City of New Knoxville	819,000	178%	436,000	48%
City of Owensville	1,397,400	-13%	1,326,400	-18%
City of Rock Falls	2,950,900	23%	3,407,000	42%
City of Wrangell	1,920,500	-7%	2,093,000	1%
East Mississippi (Henderson)	2,950,900	-11%	3,407,000	3%
Waverly Power & Light	3,474,000	-11%	4,064,000	5%
South Plains EC	866,400	266%	637,600	170%
East Mississippi (Perry Davis)	2,950,900	-19%	3,166,000	-13%

East Mississippi (Canton)	2,950,900	-8%	3,166,000	-1%
Average Error (Absolute Value)	-	*38%*	-	*26%*

Conclusions on Diesel DG Project Costs

About ten different models were initially considered for developing diesel DG project estimates. The initial options included single and multiple variable models based on total project size and number of generating units. As noted in the previous discussion, all of the models have significant error rates for certain projects because their costs varied substantially due to variables that are not quantified in the case data sets. Since most projects actually used a combination of 1,825 kW units, the number of units and total project size are closely correlated and do not improve the two variable model predictability very much over a single variable model.

The use of previously developed generation sites, standardized designs, bulk purchasing and/or used or rebuilt gensets can help lower costs. Fast track project schedules and difficult site development issues can drive project costs up.

The following list presents a summary of other significant observations made from the utility responses:

1. The total average size for a diesel fueled DG project is 6.2 MW (median size is 5.5 MW) at an average project cost of $371/kW (median of $378/kW).

2. The average and median length of warranty is five years.

3. The largest single item is the cost of the genset, which averages 55% of the total project cost.

4. A separate building enclosure is used at a minority of the sites. When present, the average cost is approximately 8% of the total project cost.

5. Switchgear and controls average about 9% of total project cost.

6. Extra emissions controls are required at a limited number of sites. When required, the cost averages only 2% of the total cost in the few cases that presented information.

7. Installation, indirect, and miscellaneous costs averaged nearly 26% of the total project costs. Even though the survey form requested breakdowns of installation components and outsourced/indirect costs, the responses provided little insight for the following reasons:
   - In-house versus outsourcing (turnkey projects) resulted in the use of lump-sum methods for tracking and reporting costs.
   - Outsourced projects included provisions for a profit but in-house expenses are recorded at cost.

– In house resource costs may not always be correctly or completely charged to the project.

The single variable polynomial model:

$$Y_2 = (437)X - (0.0094)X^2$$

Where: Y_2 = Total Project Cost, $

X = Project Size, kW

appears to be the best model for developing budgetary project estimates for project sizes ranging from 1,000-10,000 kW, when little is known about the project except for its size. However, project estimators should learn all they can about the unique site attributes and apply judgment to the initial estimates before using them for any significant commitments.

Guide for Estimating Natural Gas DG Project Costs

In contrast with the majority of the cases, only three of the case studies were natural gas fired. One case used a 4 MW combustion turbine, and the two others used a combination of 1.35 and 5 MW internal combustion engines. The variables affecting natural gas DG projects are similar to those already presented (see Table 3-6). The notable differences for natural gas versus diesel projects include:

- There are additional accessories installed on the engine to accommodate natural gas as a fuel source.
- There may be additional site development costs associated with bringing natural gas to the site.

In comparison to diesel fueled DG, the significantly smaller amount of data available on natural gas fueled units unfortunately made it difficult to develop good project costing estimators.

Table 3-11 presents a summary of the case data provided for natural gas fueled units.

Table 3-11
Natural Gas Case Study Summary

Utility	Generator Size (kW)	Type	Total Project Cost ($)	Cost per KW ($)
East Mississippi	3 - 1,350	Engine	1,954,000	482
City of Iola	2 - 5,000	Engine	9,000,000	900
Arkansas River	1 - 4,200	Turbine	2,295,000	546

Comparison of cost data for a gas and diesel project is presented in Table 3-12. While not appropriate for any sweeping conclusions, the information provides a solid example of “natural gas versus diesel” as the projects sit side-by-side at the East Mississippi Electric Power Association’s Henderson Generating Plant.

Table 3-12
Natural Gas Versus Diesel, EMEPA Henderson Plant

Item	Cost ($) Gas Units	Cost ($) Diesel Units	% Increase for gas
Genset Cost	874,109	1,806,627	na
Genset Cost per kW	216	198	9%
Total Project Cost	1,953,543	3,035,625	na
Total Project Cost per kW	$482	$333	45%

4 OPERATING COST DATA ANALYSIS AND APPLICATION GUIDE

Utility owned distributed generation facilities are typically designed to operate as either peak-shaving units or as backup units. Peak shaving units operate either during times of extreme load conditions to effectively reduce the system peak, or they may be operated when other generation plants are forced out of service. One example of a distributed generation installation is a distribution cooperative system that shaves the system peak at costs that are lower than central station peaking generation. Backup installations are typically found at facilities where a service interruption is not tolerated, such as a hospital or other health care facility. These units are automatically started in the event of a service interruption, and some installations also have an uninterruptible power supply that allows the service to be continued without a momentary interruption.

Utilities may often have a communications infrastructure that allows the unit to be started remotely. This could be accomplished through a Supervisory Control And Data Acquisition (SCADA) system, or another two-way communication system. Communication systems typically include remote monitoring and metering systems that provide system operators with data so they know the units are operating properly.

Designing a maintenance program for the distributed generation facility is crucial in order to have reliable service. Units that are not adequately maintained are more likely to break down during the critical hours of operation or not start when called upon. Long-run maintenance costs are likely to be higher if the unit is not regularly maintained. Maintenance involves both the engine and the generator, but the bulk of the maintenance is performed on the engine. Maintenance on the generator is typically limited to lubricating the bearings. There are, however, a number of electrical diagnostic tests that can be performed on the generator that require special test equipment. Maintenance programs on the engine include regular oil and filter changes, coolant fluid changes, fuel filter changes, belt replacements, and engine block heater hose replacements.

Maintenance costs for peaking installations are considered fixed costs because they generally are incurred over fixed time intervals without consideration of the annual operating hours. This only applies to distributed generation units that operate less than about 300 hours per year. For intermediate or base load distributed generation that operates for significantly more hours per year, the maintenance costs will be spread over each MWh generated. Peaking distributed generation maintenance costs are comprised of annual maintenance, unscheduled repairs, taxes, insurance, and in some cases environmental permits.

Fuel costs for diesel-fired peaking installations are typically in the range of 6.5-7.5 cents/kWh depending on the cost of fuel. Annual fixed maintenance costs are typically in the range of $2,500-5,000 per generating unit depending on the scope of tasks performed.

Summary of Case Maintenance Costs

In the case of peaking installations, maintenance costs are incurred regardless of how many hours the units are run each year. Maintenance costs do not vary with the size of the installation and it is reasonable to express costs as dollars per installation per year. Twelve of the case studies reported maintenance costs, and there was a significant range of values. The following scatter chart shows the annual maintenance costs for the various size units that are installed.

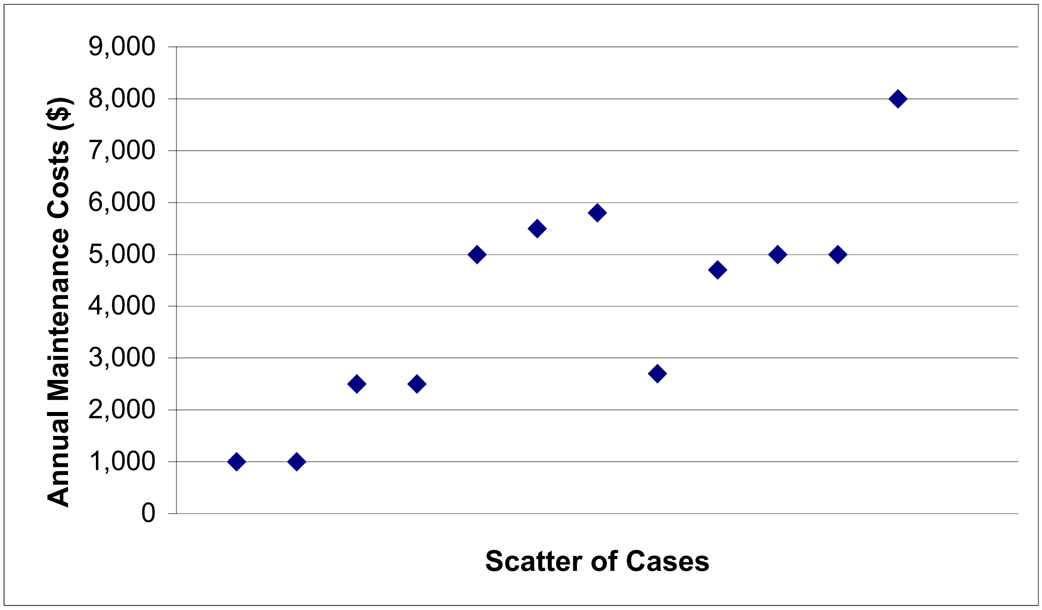


Figure 4-1
Annual Maintenance Costs

Two case studies reported maintenance costs of $1,000 per year, three reported around $2,500 per year, six were in the $5,000 range and one reported $8,000. The range of reported costs is significant, and it is driven by the extent of maintenance for each unit. The groupings of the reported maintenance will be discussed further in the discussion on difference levels of out-sourced maintenance.

Of the 12 cases reporting annual maintenance costs, nine of these purchased maintenance contracts. Of the eight cases that did not report maintenance costs, four utilized in-house maintenance services, one utilized both contract and in-house maintenance, and one out-sourced the maintenance costs. Nine of the 12 cases reporting maintenance costs were Caterpillar 3516 units. It appeared from the case studies that maintenance costs were not tracked as closely for in-source maintenance programs.

Levels of Maintenance

Case study participants reported a wide range of maintenance costs and also indicated whether they used in-house services or out-sourced for the maintenance services. Although these data points provide valuable information about the expected maintenance costs, it is worth considering a standard offering of maintenance services from a contractor. This provides an "apples to apples" comparison of the maintenance costs to the specific maintenance performed and can also be compared to case study maintenance costs. Caterpillar provides maintenance contracts for distributed generation installations and has developed multiple levels of service in what they are marketing as its "Watchguard Generator Service." Table 4-1 summarizes each level of maintenance. Caterpillar recommends that all levels of maintenance be implemented for customers who choose to contract for the maintenance services, but customers typically choose something less in order to reduce costs. Customers using the distributed generation installations to backup extremely sensitive loads are those most likely to contract for all available levels of maintenance.

Table 4-1
Summary of Caterpillar *Watchguard* Generator Service Program

Level	Description
Level 1 Comprehensive 64-point inspection	• Inspect and test engine, generator, transfer switches, day tank, battery charger, engine block heater, gauges and meters • Thoroughly check emergency engine safety shutdown systems • Test oil and coolant for contamination (ensuring they meet manufacturer's specifications) • Provide written analysis of the inspection, which will also identify areas requiring further service • Dispose all parts and fluids per EPA standards • Recommended every six to 12 months
Level 2 Comprehensive 67-point inspection plus maintenance	• Level 1 Service • Change engine oil and replace with high-grade oil; replace fuel and oil filters • Recommended every 12 months
Level 3 Cooling System Fluid Replacement	• Drain and fill the cooling system with high grade antifreeze • Replace coolant hoses, including engine block heater hoses • Replace engine thermostats and test for proper operation • Dispose all parts and fluids per EPA standards • Recommended every 24 to 36 months
Level 4 Megohmeter Testing	• Electrical windings in generators are covered with epoxy insulation. Vibration, general usage or moisture can break the epoxy down and cause electrical shorts. A Megohmeter Test will identify any decrease in epoxy capacity. • Recommended every six months for prime and continuous applications; every 12 months for load management or standby applications
Level 5	• Load Bank Testing confirms the ability of the generator to produce a given output and attain proper engine operating temperature

Level	Description

Load Bank Testing	• Benefits of load bank testing:
	  o Exercising of cooling system
	  o Reseat engine piston rings in the cylinders and liners
	  o Burn off carbon deposits in the combustion chamber, injector nozzles, piston rings, turbocharger and exhaust system
	  o Dissipate any condensation build-up on generator copper windings
	• Engine safety shutdowns are fully tested
	• Recommended every 12 months for standby applications, and every 36 months for load management applications (consists of a two hour test, unless stated otherwise)

Level 6 Engine/Generator Inspection and Adjustment	• Adjust engine valves and set to factory specifications • Check ignition and injector timing where applicable • Inspect and adjust slip ring and brushes where applicable • Check rear generator bearings, lubricate as necessary • Inspect generator wiring • Inspect space heaters • Inspect coupling and guards • Inspect generator fan drive • Inspect meters and voltage regulator as required. • Test run engine generator • Recommended every 36 months
Levels 7&8	Not Applicable
Level 9 Battery Replacement Program	• Completely check electrical system, making sure the battery charger is properly adjusted • Check engine starter and amperage under normal operating conditions • Remove and dispose of old lead acid batteries (per EPA standards) • Install new low antimony batteries…specifically designed for standby emergency generators and fire pump engines • Recommended every 24 to 36 months

Representative Contract Maintenance Costs

Table 4-2 provides estimates for all seven levels of contracted maintenance for 1,825 kW units. Dollars are reported in nominal terms and are shown for a 20-year period. Although the details of the maintenance were not provided as part of the collected case data, some observations based on the case maintenance data can be made.

In accordance with the cost estimates in Table 4-2, it appears that cases reporting $5,000 of maintenance may be receiving maintenance services equivalent to Levels 1, 2 and 4. Level 4 would require special test equipment, and this type of service may not be performed by cases that are providing their own maintenance. Cases that are reporting $2,500 of maintenance costs may be receiving Level 2 service. The costs of maintenance Level 3 are fairly significant, and only are required every three years. It does not appear that the case studies are including this service in the estimated maintenance costs because the values are only reported for one year.

Table 4-2
Sample Contract Maintenance Costs

Year	Watchguard Generator Service Level								
	Level 1	Level 2	Level 3	Level 4	Level 5	Level 6	Level 9	*Total: Levels 1,2, 4 & 9*	*Total: All Levels*
2003	$599							*$599*	*$599*
2004	$628	$2,497		$706	$3,699	$1,119		*$3,831*	*$8,649*
2005	$660	$2,622		$741	$3,884			*$4,023*	*$7,907*
2006	$693	$2,753	$4,576	$778	$4,078		$1,762	*$5,986*	*$14,640*
2007	$727	$2,891		$817	$4,281	$1,295		*$4,435*	*$10,011*
2008	$764	$3,035		$858	$4,496			*$4,657*	*$9,153*
2009	$802	$3,187	$5,298	$901	$4,720		$2,040	*$6,930*	*$16,948*
2010	$842	$3,346		$946	$4,956	$1,499		*$5,134*	*$11,589*
2011	$884	$3,514		$993	$5,204			*$5,391*	*$10,595*
2012	$928	$3,689	$6,133	$1,042	$5,464		$2,361	*$8,020*	*$19,617*
2013	$974	$3,873		$1,094	$5,738	$1,735		*$5,941*	*$13,414*
2014	$1,023	$4,067		$1,149	$6,025			*$6,239*	*$12,264*
2015	$1,074	$4,271	$7,099	$1,206	$6,326		$2,734	*$9,285*	*$22,710*
2016	$1,128	$4,484		$1,267	$6,642	$2,009		*$6,879*	*$15,530*
2017	$1,184	$4,708		$1,330	$6,974			*$7,222*	*$14,196*
2018	$1,244	$4,944	$8,218	$1,397	$7,323		$3,165	*$10,750*	*$26,291*
2019	$1,306	$5,191		$1,466	$7,689	$2,326		*$7,963*	*$17,978*
2020	$1,371	$5,450		$1,540	$8,074			*$8,361*	*$16,435*
2021	$1,440	$5,723	$9,513	$1,617	$8,477		$3,664	*$12,444*	*$30,434*
2022	$1,512	$6,009	$0	$1,698	$8,901	$2,693	$0	*$9,219*	*$20,813*

Maintenance Costs for Used Gensets

One of the cases that installed used gensets reported that they expected maintenance costs to be higher due to a problem with the engine overheating. Discussions with the Caterpillar maintenance group provided helpful information to consider when purchasing used generation equipment. A number of factors should be considered when purchasing used DG, including total number of operating hours, maintenance history, and suitability of the unit for the installation. If the DG unit has been maintained properly, but has been operated for a significant number of hours, major maintenance may be required, such as a top-end overhaul. This type of maintenance is typically required after 3,000-6,000 hours of operation, depending on how the unit has been maintained.

Used generation units may require initial maintenance to help catch up depending how the unit was maintained or how long it has been out of service. One way of estimating the initial maintenance costs of maintaining a used distributed generation facility is to price out the Caterpillar maintenance for Levels 2, 3 and 9, and assume that maintenance for Levels 3 and 9 are performed in the first year. Costs can be projected for these levels knowing that the costs provided were escalated at 5% per year. Levels 3 and 9 costs expressed in 2004 dollars are $1,598 and $4,150 respectively. A reasonable estimate for the initial maintenance costs in 2004 including Levels 2, 3, and 9 is $8,245. Bank testing could also be included in order to fully test the used machine under full load conditions. This would add $3,699 for a total of $11,944.

20-Year Net Present Value of Maintenance Costs

In order to provide guidance on what will be expected in maintenance costs, the annual costs can be evaluated over a 20-year period, based on two maintenance programs. Half of the survey results reported annual maintenance costs of $5,000 per year with only one survey reporting maintenance higher than $5,000 per year. The survey data did not include enough years to provide any guidance on maintenance that is performed intermittently such as replacing the battery bank. Manufacturers highly recommend replacing the battery bank every three years (Level 9 from Table 4-1). Based on the findings of the survey data and discussions with Caterpillar maintenance representatives, a representative level of maintenance might reflect Levels 1, 2, 4, and 9 for the 20-year period. For comparison, a “gold plated” maintenance program consisting of all levels of maintenance is also presented. Table 4-3, provides this picture of maintenance costs for a genset - by looking at the 20-year net present value of costs in Table 4-2.

Table 4-3
20-Year NPV Maintenance Costs

	Maintenance Levels 1, 2, 4, and 9	All Maintenance Levels
20 year NPV @ 7%	$61,525	$137,672
kW installed	1,825	1,825

$/kW installed	$33.71	$75.44

The 20 NPV costs of the maintenance for Levels 1, 2, 4, and 9 is approximately 10% of the installed cost of the unit, where the NPV cost of the maintenance costs for all levels would be closer to 20% of the installed cost of the unit. In considering maintenance costs, the sensitivity of a project's reliability will play key role in determining what costs might be appropriate.

Operating Costs

Operating costs are driven by the fuel costs, efficiency of the machines and number of hours of operation. Fuel consumption is directly proportional to the output of the genset and there is a range of fuel consumption rates for the various models. A range of projected fuel costs and operating hours for a Caterpillar 3516 model DM4694 are shown in Table 4-4. Fuel for units operating with natural gas would be expected to cost $2-3/Mbtu input, which is about 1/3 to ½ of operating costs using diesel.

Table 4-4
Example of Annual Operating Cost Projection, Diesel Generator

Fuel Consumption (Gal/hour)	140		
Heat Content Diesel Fuel (Btu/Gal)	139,000		
Output at Full Load (kWh/hour)	1,825		
Net Heat Rate (Btu/kWh)	10,663		
	Fuel Cost 1	**Fuel Cost 2**	**Fuel Cost 3**
Fuel Cost ($/Gal)	$0.80	$0.90	$1.00
Fuel Cost ($/MBtu)	$5.76	$6.47	$7.19
Total Operating Cost ($/MWh)	61.37	69.04	76.71
Hours Operated Per Year Scenario A	100	100	100
Hours Operated Per Year Scenario B	200	200	200
Hours Operated Per Year Scenario C	300	300	300
Total Fuel Cost Scenario A ($)	$11,200	$12,600	$14,000
Total Fuel Cost Scenario B ($)	$22,400	$25,200	$28,000

Total Fuel Cost Scenario C ($)	$33,600	$37,800	$42,000
Total Fuel Cost Scenario A ($/kW-year)	$6.14	$6.90	$7.67
Total Fuel Cost Scenario B ($/kW-year)	$12.27	$13.81	$15.34
Total Fuel Cost Scenario C ($/kW-year)	$18.41	$20.71	$23.01
Total Fuel Cost Scenario A ($/kW-month)	$0.51	$0.58	$0.64
Total Fuel Cost Scenario B ($/kW-month)	$1.02	$1.15	$1.28
Total Fuel Cost Scenario C ($/kW-month)	$1.53	$1.73	$1.92

Conclusions

Operation and maintenance are critical aspects to consider when planning for distributed generation installations. Maintenance costs for the case studies range from $1,000 to $8,000 per year, with the highest number of case studies reporting annual costs of about $5,000. Reviewing maintenance contract product offerings provides additional insights on the amount of maintenance that the manufacturer recommends, and a projection of costs. Maintenance cost projections should include services that are provided at 6- and 12-month intervals, such as inspections and oil changes, but should also include services that are recommended over longer periods of time, such as coolant changes and battery replacement. Regular maintenance is expected to be a crucial factor in maintaining a reliable DG installation and reducing long-term major maintenance costs.

Capital costs of purchasing used DG equipment are less than new equipment, but the initial maintenance costs need to be considered when making this decision. These costs could range from $8,000 to $12,000 for regular maintenance and are much higher for any major maintenance that might be required, such as a top-end overhaul.

Operating costs can be significant for units running diesel if they are operated for 300 hours per year, and the economics and payback analysis needs to consider these costs. Units running natural gas have significantly lower operating costs if they are able to purchase gas in the wholesale market at $2-3/MBtu.

5
DISTRIBUTED GENERATION PLANNING CONSIDERATIONS

Introduction

During the planning phase of the distributed generation projects, time should be allotted to investigate considerations that may impact project implementation and operations costs. Examples of these considerations are: load forecasting, system compatibility, regulatory filings and service contracts. When evaluating these considerations the cases show the need to allow planning time for program approvals and budget timelines. The time from planning to project implementation often ranges from six to eighteen months, with twelve months being fairly common for a typical installation. A typical schedule is shown in Figure 5-1.

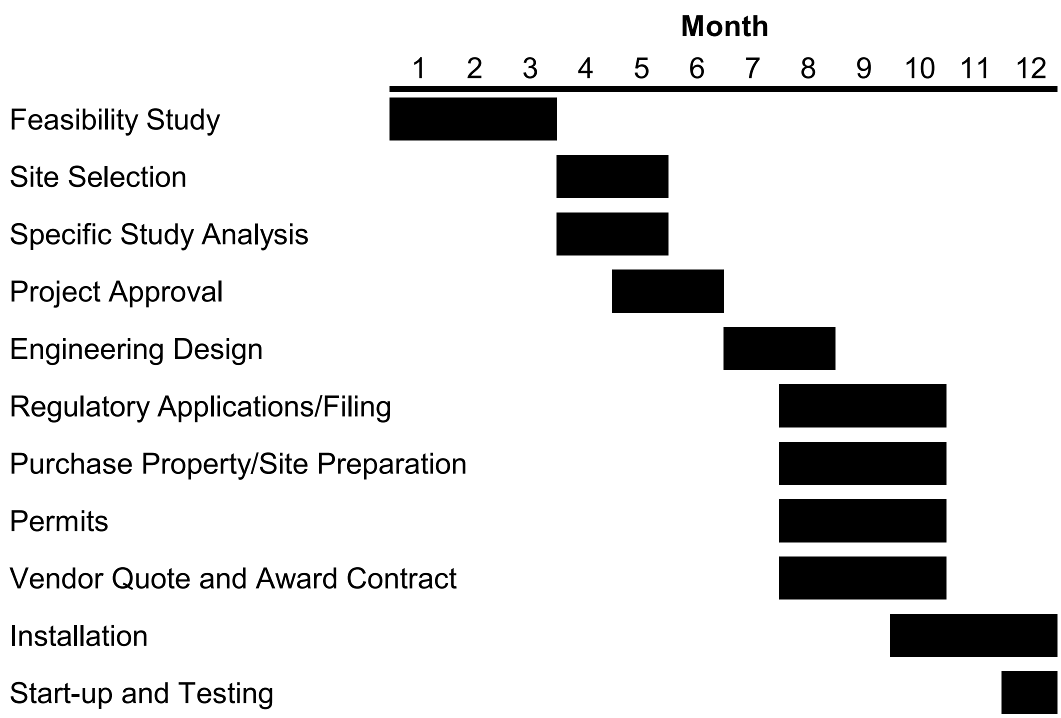


Figure 5-1
Typical Project Schedule

While a number factors or circumstances may influence the time until project implementation, key factors include:

- Reviewing power supplier contract options and peak shaving credit opportunities
- Previous experience with DG installations (either internal or with qualified outside assistance)
- Local and/or State permitting requirements
- Availability of acceptable sites
- Approval requirements of the regional reliability coordinator or independent system operator

In any particular circumstance, there could be other key factors. However with a basic assessment of the above factors, a preliminary feel for timeframe should be possible; idiosyncrasies can be addressed when appropriate.

Sources of Additional Background Information for DG

Electric utilities investigating or installing distributed generation with limited or no prior experience should visit utilities already owning, operating and maintaining DG units. Information on electric utility generation, including internal combustion and combustion turbine units, is readily available thought the US Department of Energy[3] and EPRI[4]. Utilities are also encouraged to obtain DG information and suggestions from their:

- Power supplier
- Engineering consultant
- Local vendors
- State and regional DG committees

Load Forecast

Utilizing a load or an existing forecast allows for the evaluation of data to determine the growth of a given site selection. Factors that may impact distributed generation decisions based on load forecast include:

- Size of the distributed generation unit based on usage vs. time
- Distributed generation unit uses (i.e. peak shave, base load, outage)
- Timeframe at location (permanent or temporary)
- Staging additional units at same location

[3] www.eia.doe.gov/cneaf/electricity/ipp/ipp_sum.html
[4] www.disgen.com is the repository for such information.

System Reliability Study

A system reliability study could be considered. This will identify whether proposed distribution line, transmission line, and substation upgrades could be deferred by temporary or permanent distribution generator installations. EPRI has published a spreadsheet tool to aid in this analysis[5].

Feasibility Study

A feasibility study should be performed to determine if the project would be cost effective. The feasibility study should identify expected parameters for:

- Demand charges
- Operating hours
- Engine-generator unit cost
- Relaying and switchgear cost
- Depreciated life of unit
- Fuel cost

Rate Study

To determine the impact that the distributed generation project may have on its ratepayers, a rate study is most applicable. Items that may impact electric rates, profits and/or margins may include:

- Peak demand charges
- Cost of increased capacity
- Loss of large electric use consumers
- Depreciated life of distributed generation unit

Site Selection

Reviewing all alternatives of distributed site location for the utility is recommended before deciding on a site location.

Examples that may impact site selection include:

- Power supplier policy
- Cost of additional property
- Public sensitivity to additional noise

[5] *Distributed Resources Economic Screening Tool for Transmission and Distribution Applications*, V.11/2002. EPRI, Palo Alto, CA. November 2002.1004475.

- Natural gas availability
- Zoning requirements
- Customer retention
- Low voltage along main feeder line
- Air emission impact
- Space in existing facilities
- Load growth
- Scheduled system/plant upgrades

Installation Alternatives

The utility should evaluate installation alternatives for each distributed generation project. Specific project requirements should all be identified before a vendor quote can be secured to ensure that the installation will be complete and to avoid unexpected additional costs. Design specifications should be developed to ensure that the proposed installation is properly designed.

Factors to consider when developing design specifications and vendor quotes include:

- Scope of project (One-line diagram)
- Distributed generator output voltage
- Interconnection voltage
- Generator and generator circuit breaker cost
- If used equipment is an acceptable option (Figure 5-1)
- Switchgear specifications
- Protection, control and SCADA requirements
- Type of fuel storage
- Potential environmental issues at the proposed site(s)
- Permanent or temporary location
- Desired length of warranty
- Foundation requirements
- Sound attenuation
- Sales tax, if any
- Permit fees
- Start-up and testing
- Service and maintenance contract

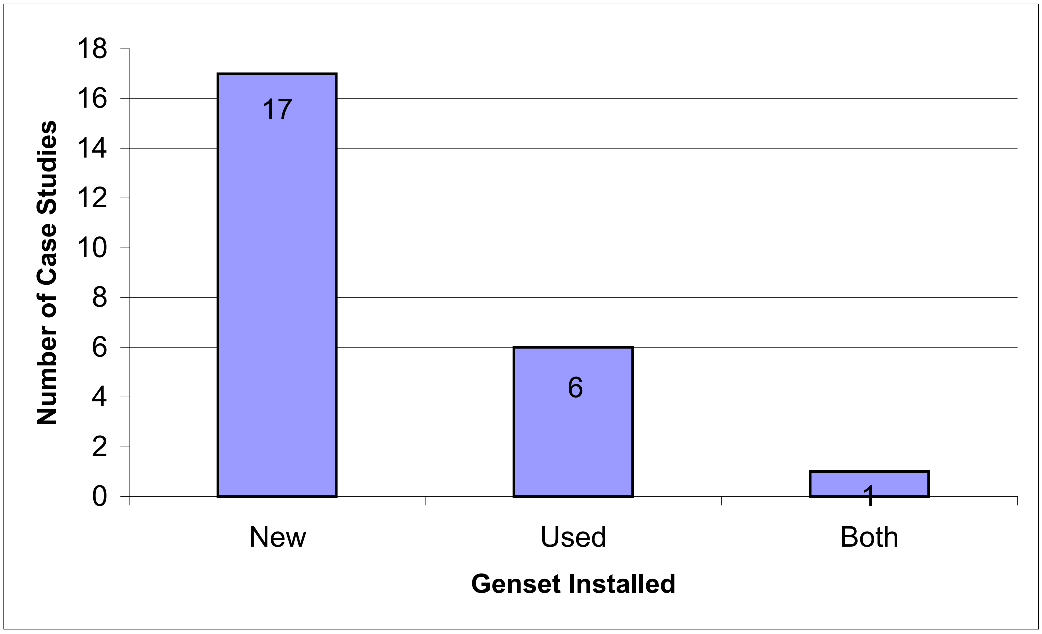


Figure 5-2
New and Used Gensets Installed

The utility also needs to evaluate if a utility personnel can perform installation or if a qualified contractor should carry out the process. Utilities identified that turnkey, design-build and design-bid-build options were all employed in the case studies (Figure 5-2). If a utility decides to solicit vendor quotes, it should consider developing a bidder list to ensure all potential bidders have the experience and expertise needed to install the generation equipment. The utility should seek references from the potential bidder for projects similar to the one being installed. If the utility decides to have a contractor install the distributed generation unit, it could still use its own personnel to install and connect the high-voltage switchgear.

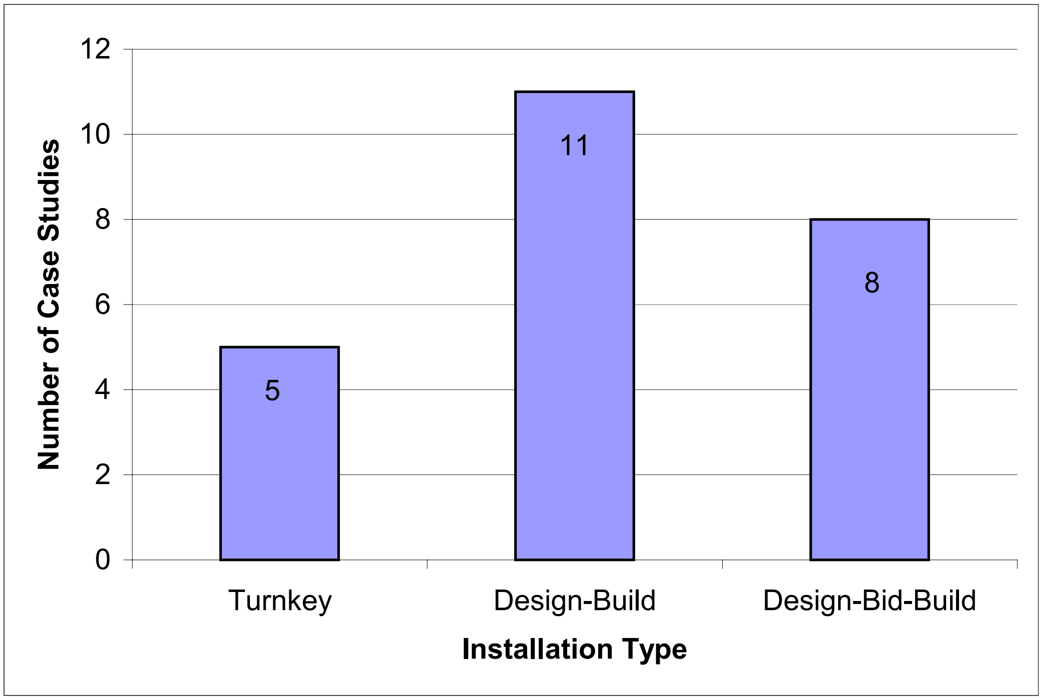


Figure 5-3
Installation Options

Regulatory Filings

Regulatory filing requirements can be an important factor impacting site selection and timeframe when the utility can install distributed generation. The utility needs to review the terms of its wholesale power supply contract and understand the interconnection approval process with its regional power pool.

The utility should review plans its power supplier may have to upgrade existing transmission lines, install new transmission lines, upgrade substations and increase capacity needs. The utility should also review any generation policies when evaluating a potential distributed generation site.

Before an interconnection agreement can be approved, the regional power pool may need to develop a policy for system review and approval. The utility needs to identify the cost and timeframe for the approval process and include it in the planning schedule.

Maintenance Contracts

Distributed generation units require scheduled maintenance to assure proper long-term operation. Most utilities that have been operating generation units for several years have trained diesel mechanics on staff. These utilities decided to have internal staff perform maintenance activities. Utilities with no distributed generation experience negotiated multi-year service contracts with maintenance service providers to perform the maintenance activities. The utility will need to forecast planned vs. actual operating hours to determine maintenance requirements and an annual maintenance budget. The utility should determine if existing personnel will have enough staff time to maintain the units. The majority of utilities providing information for this study showed that actual operating hours were less than planned operating hours.

In summary, utilities should:

- Evaluate qualifications and available staff time of current personnel
- Evaluate warranty terms for maintenance requirements
- Contract for services as required (Figures 5-3 and 5-4)

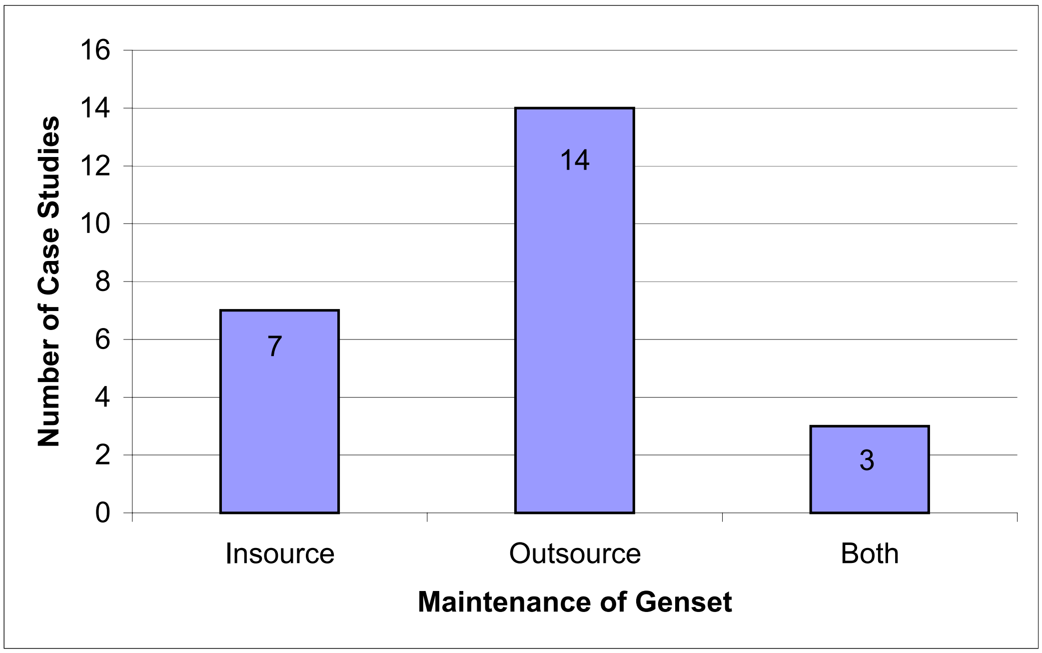


Figure 5-4
Insource vs. Outsource Choices of Case Study Responses

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Figure 5-5
Typical Annual Maintenance Costs

Maintenance Considerations for Used Gensets

All of the case studies identified brand name distributed generation units that have been in existence for several years. These providers generally have maintenance manuals for utilities to use to schedule maintenance activities. Maintenance activities are usually based on the actual operating hours of the distributed generation unit. If the utility is considering a used generator, it should review the required maintenance based on its actual operating hours before finalizing the purchase.

Typical maintenance activities include:

- Clean and check battery and connection
- Clean spark arrester
- Change oil and filter
- Change air filter
- Change fuel filter
- Overhaul engine

Conclusion

Similar to other engineering projects, the planning phase of a DG project can have important implications in terms of its overall success. Time should be allotted to investigate considerations and factors that may impact a project. While there stand to be unique circumstances for any project, there are a number of steps that are common to most successful projects. The amount of time necessary for each step can be expected to vary amongst utilities and installations; however by addressing the common overall planning considerations a utility is in the a position to make the best decision(s) possible.

6
ENVIRONMENTAL FACTORS ASSOCIATED WITH DG PROJECT SITES

Distributed generation from 1 to 10 MW in size falls "in between" the large central station plants that are highly regulated and require an array of environmental permits and pollution credits and the individual home or small business sites that require few, if any, approvals. This midsize DG can be best characterized by the term "it depends," because requirements will vary widely from state to state, region to region and site to site depending on local laws and ordinances, which are unique to each locale's circumstances and preferences.

The environmental issues for DG projects include the following:

- Aesthetics (neighbors and projects in public view)
- Air quality (pollutant emissions)
- Hazards and hazardous materials (equipment chemicals, ammonia if certain control technologies are used to minimize pollutant emissions)
- Noise (decibel level of equipment operations)
- Land use and planning
- Geology, soils, hydrology and water quality

Air quality is usually the most demanding environmental consideration. In the United States, air pollution has been traditionally divided into four categories. These are:

1. criteria pollutants (carbon monoxide, nitrogen oxides, sulfur oxides, ozone, volatile organic compounds and lead)
2. toxic compounds
3. ozone depleting compounds
4. global warming compounds

Air quality issues are addressed at three primary levels: global (such as #3 and #4), regional and local (as in #1 and #2). Global considerations are a relatively minor factor because of the low run-hours of DG. Local and regional requirements tend to be the most important. However, there are increasing collaborations across state lines, and most recently across national borders (between Canada and northeastern states), on air quality issues and regulations.

At the federal level, the EPA is authorized under the Clean Air Act to set limits on how much of a pollutant can be emitted according to the National Air Quality Standards (NAAQS). Permits to emit airborne pollutants are issued by Air Quality Management Districts (AQMDs), regional bodies that include all or parts of individual states. The permits themselves include information on which pollutants are being emitted, allowable emissions rates, and any efforts, such as air quality monitoring, that responsible individuals and corporations either already are taking or will be required to take. These documents are intended to ensure that air quality regulation at the state level meets federal air quality standards, although there are an increasing number of states establishing more stringent standards than the Federal standards. The procedures for issuing permits within a given state contribute to its State Implementation Plan (SIP), or the collection of all those rules and regulations the state has developed to improve air quality within its borders. SIPs are subject to approval by the EPA and must comply with the Lowest Achievable Emissions Rate (LAER) as specified by section 171 of the Clean Air Act.

An increasing number of states, including California, Colorado and Texas, delegate source permitting authority to the local level for certain types of installations[6]. It is not uncommon to have different compliance requirements for identical installations in the same region that fall into different locales. Similarly, two engine generators on the same site can fall under differing requirements because of their size, with the local authorities having responsibility for smaller sizes and state retaining responsibility for medium and larger sizes. For 1 to 10 MW distributed generation local requirements are most often applicable.

Requirements for air permits vary widely with many locales providing conditional permits or permit exemptions based on the low number of annual run hours (200 or 300 hours per year is a common breakpoint). Documentation to prove annual run hours is required and fines/penalties are assessed for exceeding the limits. Because of the low number of run hours DG installations normally require only periodic emissions tests rather than continuous monitoring which is required for larger installations with high run time hours.

Some states or locales apply cost factors that can mandate the inclusion of post combustion emissions controls if the costs per ton of emissions reduction are below certain specified values. Such regulations have their roots in the Section 169 of the Clean Air Act, which specifies the Best Achievable Control Technology (BACT) based on energy, environmental, and economic impacts and other costs[7]. It must also be kept in mind that regulations do change and increasingly often "grandfathering" is not allowed. Additional emissions reduction technologies may become a requirement at a later point. Because of the complexity and uniqueness of obtaining air quality permits and approvals, it is advisable to consider the use of an experienced consultant to assist in-house resources on this critical issue.

Understanding and finding all the different entities that may require approvals/permits can be a daunting task. However resources are out there that can help in this process[8]. As an example, a proposed site in Irvine, California, would require contacting the following agencies[9].

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[6] Guidance for the Permitting of Electrical Generation Technologies, California Air Resource Board/EPA, July 2002

[7] Guidance for the Permitting of Electrical Generation Technologies, California Air Resource Board/EPA, July 2002

[8] See http://www.cleanairworld.org/scripts/regions.asp?id=307 for a state-by-state listing of agencies.

- Santa Barbara County Air Pollution Control District
- County Building Department
- County Planning & Zoning
- County Fire Department
- County Environmental Health Services
- Southern California Gas Company
- The City of Irvine

In the smaller 1 MW to 3 MW sizes, DG is predominantly internal combustion engines with diesel as the fuel. This is largely due to cost and quickness of starting these units. Larger installations see more combustion turbines fired by natural gas due to air quality considerations (higher run hours and cleaner burning). There is growing interest in natural gas in the smaller engines for reasons of air quality; however, gas engines are significantly higher in cost than diesel engines, which will hinder any move from diesel to gas. It should be noted, however, that local air quality requirements are changing more rapidly today in many parts of the country as communities grow more aware of the environmental elements in their communities. California, for example, has a number of districts that are developing BACT requirements that are fuel neutral. Present diesel fired reciprocating gensets would not be able to meet these requirements should they go forward.

The California Air Resource Board (CARB) has published has best Available Control Technology (BACT) guidelines for distributed generators[10].

[9] Distributed Generation Case Studies for Permit Streamlining and the Impact Upon Transmission and Distribution Services, State of California Energy Commission, January 2002

[10] Guidance for the Permitting of Electrical Generation Technologies. California Air Resources Board, Stationary Source Division, Project Assessment Branch. July 2002.

7
RECOMMENDATIONS

The main focus of this study was to gather detailed cost data on a variety of DG project sites with units ranging from 1 MW to 10 MW output. A fairly substantial list of utilities that had DG units in operation was assembled, but many potential respondents were reluctant to provide information. Utility staff were generally willing to discuss their projects in qualitative terms, but they were not enthusiastic about digging into closed project files for the detailed cost data. Lump sum cost information was available, but it comes without detail that would allow the project costs to be broken down into components.

A large majority of existing units are sized in the range of 1.8 MW to 2 MW. This size is the largest skid-mounted engine generator unit that can be easily shipped to a site as a single assembly. The cost of these units on a per kW basis is somewhat lower than smaller or larger units. The 1.8-MW to 2-MW unit is manufactured in significant quantities for rental fleets, and these units are easily adapted to permanent installations. The units are equipped with all of the basic controls for standalone operation or in parallel operation with an electric utility grid. It is easy to connect multiple units in parallel for projects with larger requirements.

The cases had a wide range of total project costs, even for projects using the 1.8-MW to 2-MW units. It appears that each project has many unique features associated with its location that drive installation costs up or down from the average. It also appears that projects installed in environmentally sensitive areas that need high quality enclosures and interconnection equipment installed in enclosures cost the most. The most economical installations tend to be in rural substations or at sites where generation equipment was previously installed and then retired.

The following general procedure for estimating the cost of a potential DG project alternative is recommended:

1. Obtain preliminary environmental information about the potential site concerning:
   - Is the location rural or urban?
   - Is the site relatively flat?
   - How close is the existing electrical system to the proposed site?
   - Is a pre-manufactured enclosure satisfactory or will a building be required?
2. Identify the project service date.
3. Assess the DG equipment market.
4. Use the guidelines in Sections 3 and 4 to develop a baseline project estimate.

5. Review the case overviews and summaries presented in Section 2. Compare the baseline project estimate with the reported costs for a couple of cases that are similar to the proposed project.

6. Adjust the estimate up or down as required to recognize any unique requirements of the proposed project.

7. Crosscheck current genset supplier data against the final estimate. In many circumstances, the supplier's genset cost should not exceed 65% of total project cost.

A
SURVEY RESPONSES

Anonymous Utility A

1.0 Project name and location:

1.1 Generator type: (Combustion turbine or reciprocating engine) Reciprocating

1.2 Size(s) (kW) and installation dates: 2-1250 kW, 1-900 kW 2000

1.3 Voltage of generator and grid interconnection: 488 V – 14.4/24.9 kV

1.4 Fuel type(s): diesel

2.0 How many hours per year were the generator(s) operated?

	----- PLANT		UNIT NO. 2	
YEAR	PLANNED HOURS	ACTUAL HOURS	PLANNED HOURS	ACTUAL HOURS
2002	74	30		
2001	75	165		
2000	testing	Testing		
1999	---	---		
1998	---	---		
1997	---	---		
1996	---	---		

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? 20 years w/maintenance

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.). design – bid - build

4.0 How much time was required from project authorization completion? 16 mos.

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)? Air quality (2 mos) zoning (2 mos)

4.2 What was the approximate total installed cost of the project and cost per kW of net output? $1,900,000 $560/kW nameplate; $703/kW @ 80%/nameplate

4.3 What is the average fuel cost per kWH? $0.145/kWH

4.4 What are the actual maintenance costs per kWH per month (or year)? $8,000/yr

Anonymous Utility B

1.0 Project name and location:

1.1 Generator type: (Combustion turbine or reciprocating engine) Reciprocating Engine

1.2 Size(s) (kW) and installation dates: 2 1825 kW units December 2000

1.3 Voltage of generator and grid interconnection: 4160/2400

1.5 Fuel type(s): Diesel

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1		UNIT NO. 2	
YEAR	PLANNED HOURS	ACTUAL HOURS	PLANNED HOURS	ACTUAL HOURS
2002	200	106 to date	200	107 to date
2001	200	112	200	115
2000				
1999				
1998				
1997				
1996				

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? 18 months

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc) design, bid, build

4.0 How much time was required from project authorization completion? Two years

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)? emissions two months

4.2 What was the approximate total installed cost of the project and cost per kW of net output? $1,532,057 $419.00

4.3 What is the average fuel cost per kWH? $.06

4.5 What are the actual maintenance costs per kWH per month (or year)? Unknown

Anonymous Utility C

1.0 Project name and location:__________

1.1 Generator type: (Combustion turbine or reciprocating engine) Internal combustion

1.2 Size(s) (kW) and installation dates: 3 – 2000 kW

1.3 Voltage of generator and grid interconnection:__________

1.6 Fuel type(s): diesel

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1		UNIT NO. 2	
YEAR	PLANNED HOURS	ACTUAL HOURS	PLANNED HOURS	ACTUAL HOURS
2002				
2001		64.75		64.25
2000				
1999				
	UNIT NO. 3			
	PLANNED HOURS	ACTUAL HOURS		
2002				
2001		56.50		
2000				
1999				
1998				
1997				
1996				

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? __________

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.). __________

4.0 How much time was required from project authorization completion? __________

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)? Air emission

4.2 What was the approximate total installed cost of the project and cost per kW of net output?
$1,649,846 $274.97/kW

4.3 What is the average fuel cost per kWH? __________

4.6 What are the actual maintenance costs per kWH per month (or year)? __________

Anonymous Utility D

1.0 Project name and location:

1.1 Generator type: (Combustion turbine or reciprocating engine) reciprocating engine

1.2 Size(s) (kW) and installation dates: 1825 kW 10-2000

1.3 Voltage of generator and grid interconnection: 4160

1.7 Fuel type(s): diesel

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1		**UNIT NO. 2**	
YEAR	PLANNED HOURS	ACTUAL HOURS	PLANNED HOURS	ACTUAL HOURS
2002		45		
2001		45		
2000		10		
1999				
1998				
1997				
1996				

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life?

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.) design – bid - build

4.0 How much time was required from project authorization completion?

18 months

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)?

Emission, storage, minimal time

4.2 What was the approximate total installed cost of the project and cost per kW of net output?

$706.929 ÷ 1825 = $387.36

4.3 What is the average fuel cost per kWH?

4.7 What are the actual maintenance costs per kWH per month (or year)? $459/mo.

Anonymous Utility E

1.0 Project name and location:

1.1 Generator type: (Combustion turbine or reciprocating engine) Reciprocating engine

1.2 Size(s) (kW) and installation dates: 1360 kW (1998) Fall 1954 model

1.3 Voltage of generator and grid interconnection: 2400 Δ

1.8 Fuel type(s): Dual fuel - diesel and natural gas

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1		UNIT NO. 2	
YEAR	PLANNED HOURS	ACTUAL HOURS	PLANNED HOURS	ACTUAL HOURS
2002	As needed	2.6		
2001	As needed	130.3		
2000	Unknown	84.1		
1999	200	163.8		
1998	0	0		

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? 20 or more years

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.). The unit was purchased as used equipment having the same basic size in capacity and same primary voltage as the unit it replaced. The only modifications in design were to the engine base. And some piping changes which were handled by contractors. The unit purchased was a used generating unit from a private contractor.

4.0 How much time was required from project authorization completion? 7 months

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)? Construction permit required by the emissions KDHE (3 months)

4.2 What was the approximate total installed cost of the project and cost per kW of net output? $434,500.00 total $320.00 per kW

4.3 What is the average fuel cost per kWH? .042 dependent on market pricing

4.8 What are the actual maintenance costs per kWH per month (or year)? N/A

Anonymous Utility F

1.0 Project name and location:

1.1 Generator type: (Combustion turbine or reciprocating engine) RE

1.2 Size(s) (kW) and installation dates: (1) 1950, (1) 2200, (1) 6200, (7) 2000 1956 to 2002

1.3 Voltage of generator and grid interconnection:

1.9 Fuel type(s): Diesel and natural gas

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1		UNIT NO. 2	
YEAR	PLANNED HOURS	ACTUAL HOURS	PLANNED HOURS	ACTUAL HOURS
2002		150		
2001		“		
2000		“		
1999		“		
1998		Average		
1997		“		
1996		“		

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? 30 years

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.). Design – bid - build

4.0 How much time was required from project authorization completion?

Typically 9 months

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)?

Air emission, construction, stack dusting

4.2 What was the approximate total installed cost of the project and cost per kW of net output?

Varies from $900,000 to $2,000,000

4.3 What is the average fuel cost per kWH?

4.9 What are the actual maintenance costs per kWH per month (or year)? Varies – 60% in-house resources, 40% contracted

Anonymous Utility G

1.0 Project name and location: USBank, Gresham, OR

1.1 Generator type: (Combustion turbine or reciprocating engine) Recip

1.2 Size(s) (kW) and installation dates: (4) gensets @ 1.6 MW each

1.3 Voltage of generator and grid interconnection: 12,700 v

1.10 Fuel type(s): diesel

2.0 How many hours per year were the generator(s) operated?(Note: all gens are run simultaneously)

	UNIT NO. 1		UNIT NO. 2	
YEAR	PLANNED HOURS	ACTUAL HOURS	PLANNED HOURS	ACTUAL HOURS
2002	100	0 in DG 38 in 'outage mode		
2001	N/A	N/A		
2000				
1999				

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? 10 yr lease agreement, renewable

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.).

PGE has a "dispatchable generation" program which leases customers existing or new generation. PGE runs the equipment as a peaking resource (up to 400 hrs/yr) and in return pays for all fuel and maintenance. Customer is also protected from outages by their generation. The site discussed herein was 10 years old at the time of conversion to a d.G. site. A design/bid/build process was used for the conversion.

4.0 How much time was required from project authorization completion? 18 months

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)? Emissions permit from Oregon Dept of Env. Quality

4.2 What was the approximate total installed cost of the project and cost per kW of net output? Total paralleling project cost $842,000; or $131.60 kW (original generator system cost is not available to us) Note: Cost shown on 4.2 includes one time payment to Owner.

4.3 What is the average fuel cost per kWH? $0.09

4.10 What are the actual maintenance costs per kWH per month (or year)? At low hrs/yr, maintenance is basically fixed

Anonymous Utility H

1.0 Project name and location: Back

1.1 Generator type: (Combustion turbine or reciprocating engine) reciprocating

1.2 Size(s) (kW) and installation dates: 600 kW - 2,600 kW, 1998-2001

1.3 Voltage of generator and grid interconnection: 208-3Ø, 480-3Ø 13,800 v-3Ø

1.11 Fuel type(s): Ultra-low sulfur diesel fuel, 30 ppm sulfur

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1		UNIT NO. 2	
YEAR	PLANNED HOURS	ACTUAL HOURS	PLANNED HOURS	ACTUAL HOURS
2002		22		
2001		16		
2000		17		
1999		14		
1998		0		
1997				
1996				

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? When they become obsolete

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.).

we own, install, operate and maintain generators at customer sites

4.0 How much time was required from project authorization completion? 6 mos.

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)? Air permits can take up to 1 year, zoning about 1 month, storage tanks-several months.

4.2 What was the approximate total installed cost of the project and cost per kW of net output?

4.3 What is the average fuel cost per kWH?

4.11 What are the actual maintenance costs per kWH per month (or year)? $150,000 per year

Central Virginia Electric Coop

1.0 Project name and location: cooperative subsidiary – CEVA Energy

1.1 Generator type: (Combustion turbine or reciprocating engine) reciprocating engine

1.2 Size(s) (kW) and installation dates: ten – 2,000 kW units

1.3 Voltage of generator and grid interconnection: 480 volt generation – 12.5 kV and 24.9 kV grid

1.12 Fuel type(s): diesel

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1		UNIT NO. 2	
YEAR	PLANNED HOURS	ACTUAL HOURS	PLANNED HOURS	ACTUAL HOURS
2002	680	308 thru Sept		
2001	150	272		
2000	120	190		
1999				
1998				
1997				
1996				

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? Until Jan 1, 2005, change in wholesale contract

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.).

The project was implemented as a turn-key design provided to coop. large power customers, owned and operated by CEVA Energy (Coop's subsidiary). CAT generator dealer provided generator, fueling and switchgear, turnkey to coop specs. Coop engineering did concrete pad layout and SCADA interface and isolation switch control design, working with switch manufacturer, and procured contractor for installation.

4.0 How much time was required from project authorization completion? First generator – about 12 mos, using some design for all others – 6 mos.

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)?

Emissions for all units – 6-8 weeks

Zoning for one unit – 3 mos

4.2 What was the approximate total installed cost of the project and cost per kW of net output?

4.3 What is the average fuel cost per kWH? $.055 (2001)

4.12 What are the actual maintenance costs per kWH per month (or year)? $.012 (2001)

City of Fennimore

1.0 Project name and location: Fenimore Power Plant

1.1 Generator type: (Combustion turbine or reciprocating engine) IC

1.2 Size(s) (kW) and installation dates: 1961-2000

1.3 Voltage of generator and grid interconnection: 4160

1.13 Fuel type(s): diesel

2.0 How many hours per year were the generator(s) operated?

UNITS 1,2,3	PLANNED	ACTUAL	**UNIT 4**	PLANNED	ACTUAL
2002			**2002**		
2001		80	**2001**		30
2000		132	**2000**		50
1999			**1999**		100
1998			**1998**		100
1997			**1997**		
1996			**1996**		
UNIT 5	PLANNED	ACTUAL			
2002					
2001		40			
2000		60			
1999		100			
1998		100			
1997					
1996					

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life?

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.).

Design-bid-build

4.0 How much time was required from project authorization completion? 6-7 weeks

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)? Not too much time. Fuel permit w/DNR

4.2 What was the approximate total installed cost of the project and cost per kW of net output?

Approximate total installed cost of the project – projected $538,921/engine; # x 3 = 1,685,815

$308 cost per KW net output

4.3 What is the average fuel cost per kWH? 2.5¢

4.13 What are the actual maintenance costs per kWH per month (or year)?

City of Garnett

1.0 Project name and location: Garnett Municipal Power Plant, Addn'l Generation-EMD Model 20-645-E4

1.1 Generator type: (Combustion turbine or reciprocating engine) Reciprocating Engine

1.2 Size(s) (kW) and installation dates: 2500kW, August 2000

1.3 Voltage of generator and grid interconnection: Gen.: 4160 kV Inter.: 4160 kV

1.14 Fuel type(s): Diesel

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1		UNIT NO. 2	
YEAR	PLANNED HOURS	ACTUAL HOURS	PLANNED HOURS	ACTUAL HOURS
2002		To date: 10		
2001		98		
2000		118		
1999				
1998				
1997				
1996				

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? 20 years

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.).

Turn-key project

4.0 How much time was required from project authorization completion? Six (6) mos. Authorized in February, completed in August, 2000

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)? KDHE Emissions Permit, approximately 60 days

4.2 What was the approximate total installed cost of the project and cost per kW of net output? Approximate total cost of project: $861,540.; $344.61 per kW

4.3 What is the average fuel cost per kWH? 5.9 cents

4.14 What are the actual maintenance costs per kWH per month (or year)? Approx.$250 per month

City of Iola

1.0 Project name and location: Iola, Kansas

1.1 Generator type: (Combustion turbine or reciprocating engine) Reciprocating

1.2 Size(s) (kW) and installation dates: 2- 5000 kW 1997, 1999

1.3 Voltage of generator and grid interconnection: 12470

1.15 Fuel type(s): Natural Gas

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1		UNIT NO. 2	
YEAR	PLANNED HOURS	ACTUAL HOURS	PLANNED HOURS	ACTUAL HOURS
2002				
2001		994		330
2000		1137		842
1999		681		
1998		375		
1997				
1996				

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? 40 years

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.).

Turn-key by company

4.0 How much time was required from project authorization completion?

10 months

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)?

Emission permits 4 months

4.2 What was the approximate total installed cost of the project and cost per kW of net output?

$1,035.00

4.3 What is the average fuel cost per kWH?

4.15 What are the actual maintenance costs per kWH per month (or year)?

City of New Knoxville

1.0 Project name and location: Peaking unit

1.1 Generator type: (Combustion turbine or reciprocating engine) reciprocating engine

1.2 Size(s) (kW) and installation dates: 1000 kW

1.3 Voltage of generator and grid interconnection: 480 to 12,470

1.16 Fuel type(s): diesel

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1		UNIT NO. 2	
YEAR	PLANNED HOURS	ACTUAL HOURS	PLANNED HOURS	ACTUAL HOURS
2002	160	10		
2001	160	50		
2000	160	40		
1999	NA			
1998	NA			
1997	NA			
1996	NA			

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? 20 years

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.). We did it all in-house

4.0 How much time was required from project authorization completion? 8 weeks

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)?

EPA 14 weeks for air pollution

4.2 What was the approximate total installed cost of the project and cost per kW of net output?

$200,000 cost around $90.00/kWH

4.3 What is the average fuel cost per kWH? $69.00

4.16 What are the actual maintenance costs per kWH per month (or year)? @ $2,500 total for year

City of Owensville, MI

1.0 Project name and location: Not doing a project

1.1 Generator type: (Combustion turbine or reciprocating engine) Diesel

1.2 Size(s) (kW) and installation dates: 4 – 1,825 kW

1.3 Voltage of generator and grid interconnection: 34,500

1.17 Fuel type(s): Diesel

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1		UNIT NO. 2	
YEAR	PLANNED HOURS	ACTUAL HOURS	PLANNED HOURS	ACTUAL HOURS
2002		10		10
2001		500		500
2000				
1999				
1998				
1997				
1996				

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life?

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.). Complete turn-key design

We already had a plant, we just added 4 engines

4.0 How much time was required from project authorization completion?

Approx. 1 year

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)?

Was done thru the company with the turn-key

4.2 What was the approximate total installed cost of the project and cost per kW of net output?

$600,000 per unit

4.3 What is the average fuel cost per kWH?

4.17 What are the actual maintenance costs per kWH per month (or year)?

City of Rock Falls, IL

1.0 Project name and location: Rock Falls Generating Plant units 3-4-5-6-7

1.1 Generator type: (Combustion turbine or reciprocating engine) Combustion

1.2 Size(s) (kW) and installation dates: All 1.825 mW – 2 units Feb 2000 – 5 units 2001

1.3 Voltage of generator and grid interconnection: 12 kV to 34.5 kV

1.18 Fuel type(s): Distillate fuel

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1		UNIT NO. 2	
YEAR	PLANNED HOURS	ACTUAL HOURS	PLANNED HOURS	ACTUAL HOURS
2002	200 ea	16 hr ea	UNIT	
2001				
2000				
1999				
1998				
1997				
1996				

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? 20 years

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.) design build

4.0 How much time was required from project authorization completion? 1 yr

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)? 6 mos.

4.2 What was the approximate total installed cost of the project and cost per kW of net output?
$274.00

4.3 What is the average fuel cost per kWH? 6.5¢

4.18 What are the actual maintenance costs per kWH per month (or year)? $1.00 kW

City of St George, UT

1.0 Project name and location: Redrock

1.1 Generator type: (Combustion turbine or reciprocating engine) Recip.

1.2 Size(s) (kW) and installation dates: 2 - MW 4/8/87

1.3 Voltage of generator and grid interconnection: 6.9 kV

1.19 Fuel type(s): diesel

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1		UNIT NO. 2	
YEAR	PLANNED HOURS	ACTUAL HOURS	PLANNED HOURS	ACTUAL HOURS
2002		867		
2001		2863		
2000		160		
1999		272		
1998				
1997				
1996				

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? 50 yrs

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.). Design build

4.0 How much time was required from project authorization completion? 1 yr

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)?
Conditional use and air quality

4.2 What was the approximate total installed cost of the project and cost per kW of net output?
5.5 million

4.3 What is the average fuel cost per kWH?

4.19 What are the actual maintenance costs per kWH per month (or year)?

City of Wrangell, AK

1.0 Project name and location: Wrangell Light and Power

1.1 Generator type: (Combustion turbine or reciprocating engine) RE

1.2 Size(s) (kW) and installation dates: (3) @ 2 MW and (1) @ 2.5 MW

1.3 Voltage of generator and grid interconnection:

1.20 Fuel type(s): Diesel

2.0 How many hours per year were the generator(s) operated? See spreadsheet

	UNIT NO. 1	UNIT NO. 2	UNIT NO. 3	UNIT NO. 4
YEAR	ACTUAL HOURS	ACTUAL HOURS	ACTUAL HOURS	ACTUAL HOURS
2002	273	88	145	70.5
2001	159.5	313		313
2000	290	154		103
1999	2383.7			
1998	221			
1997	177.5			
1996	193			

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? 30 years

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.). design build

4.0 How much time was required from project authorization completion?

1 year

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)?

No permits required

4.2 What was the approximate total installed cost of the project and cost per kW of net output?

$1,770,000, new switchgear, 3 EMD

4.3 What is the average fuel cost per kWH? 8.2/kWH

4.20 What are the actual maintenance costs per kWH per month (or year)? $6.30/kwh/yr

(In-house resources)

East Mississippi - Meridian

1.0 Project name and location: Davis Generating Station – Within NAS Meridian, MS

1.1 Generator type: (Combustion turbine or reciprocating engine) Reciprocating Engine

1.2 Size(s) (kW) and installation dates: 1825 kW January, 1998

1.3 Voltage of generator and grid interconnection: 4160

1.21 Fuel type(s): Diesel

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1	UNIT NO. 2	UNIT NO. 3	UNIT NO. 4
YEAR	ACTUAL HOURS	ACTUAL HOURS	ACTUAL HOURS	ACTUAL HOURS
2002				
2001	300	300	**300**	300
2000	300	300	**300**	300
1999	300	300	**300**	300
1998	300	300	**300**	300

2.1 What is the expected project life? 20 years

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.).

The project was originally designed by East Mississippi Electric Power Association in support of its largest customer. The customer, Meridian Naval Air Station was served by a single 46 kV readial transmission line that experienced extended outages. During military closure hearings it was decided that such exposure to outage was unacceptable. EMEPA approached TVA with the concept and ultimately partnered with TVA to implement the project. The final design was developed by TVA's Synterprise Group and was built by them using internal forces and contractor support in a 99 day period beginning in September 1997. Testing and commissioning was completed within this 99 day period. The contract began on January 1, 1998. Final work was completed on December 31, 1997. Since that time the project has been operated and maintained in a joint effort by TVA, AMAPA and the maintenance contractor, Thompson Power of Nashville, TN.

4.0 How much time was required from project authorization completion? 6 months

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)?

Emissions permitting took approximately 3 months. No other permits were required since this was on military property .

4.2 What was the approximate total installed cost of the project and cost per kW of net output?

$3,500,000 $383/kW

4.3 What is the average fuel cost per kWH? $0.048

4.21 What are the actual maintenance costs per kWH per month (or year)? $0.018

East Mississippi – Canton, MS

1.0 Project name and location: Canton, MS Generating Station

1.1 Generator type: (Combustion turbine or reciprocating engine) Reciprocating Engines

1.2 Size(s) (kW) and installation dates: 2000 kW June, 2002

1.3 Voltage of generator and grid interconnection: 4160

1.22 Fuel type(s): Diesel

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1	UNIT NO. 2	UNIT NO. 3	UNIT NO. 4
YEAR	ACTUAL HOURS	ACTUAL HOURS	HOURS	ACTUAL HOURS
2002				
2001	300	300	**300**	300
2000				
1999				
1998				
1997				
1996				

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? 20 yrs

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.).

Canton Municipal had previously purchased all its power from the local investor owned utility. However, it had the option of providing some of its own resources. During the price spikes of 1999, it was decided to add several units of peaking generation. This was planned for during the later part of 2000 and early 2001. The work was design build project. Ultimately, the equipment supplier became responsible for maintenance of the facility. Since no emissions permit existed, a new permit was processed using a consultant who specialized in such submittals. The machines were low emissions units but no special treatment of the exhaust stream was employed.

4.0 How much time was required from project authorization completion? Approximately fourteen months. Since the peak load period would be missed the first year, there was no urgent rush until the following year.

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)?

See notes above.

4.2 What was the approximate total installed cost of the project and cost per kW of net output?

$3,472,900 $347/kW

4.3 What is the average fuel cost per kWH? $0.046/kWH

4.22 What are the actual maintenance costs per kWH per month (or year)? $0.018/kWH

East Mississippi Henderson Diesel 1825 kW

1.0 Project name and location: Henderson Station-Peaking Generation – 1825 kW units

1.1 Generator type: (Combustion turbine or reciprocating engine) Reciprocating Engines

1.2 Size(s) (kW) and installation dates: 1825 kW June, 2001

1.3 Voltage of generator and grid interconnection: 4160

1.23 Fuel type(s): Diesel

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1	UNIT NO. 2	UNIT NO. 3	UNIT NO. 4
YEAR	ACTUAL HOURS	ACTUAL HOURS	ACTUAL HOURS	ACTUAL HOURS
2002				
2001	98	90	**93**	105
2000				
1999				
1998				
1997				
1996				

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? 20 years

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.).

Greenwood Utilities operates approximately 70 MWs of generation. Some coal, some natural gas turbine. Because of the extreme price fluctuation experienced in recent years, it was decided to add approximately 10 mWs of peaking generation. The work was a design build project. Ultimately, the equipment supplier became responsible for maintenance of the facility. To meet the emissions permit existing at the facility, Selective Catalytic Reactors (UREA is the agent) was used on three of the five diesel machines. A picture of this exhaust installation is attached.

4.0 How much time was required from project authorization completion? Approximately eight months

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)?

An existing Title V permit existed and it was amended. All other permits were already existing for the facility.

4.2 What was the approximate total installed cost of the project and cost per kW of net output?

$3,391,304

$339/kW

4.3 What is the average fuel cost per kWH? $0.046/kWH

4.23 What are the actual maintenance costs per kWH per month (or year)? $0.018 per kWH

East Mississippi Henderson Diesel 200 kW

1.0 Project name and location: Henderson Station-Peaking Generation - 2000 kW units

1.1 Generator type: (Combustion turbine or reciprocating engine) Reciprocating Engines

1.2 Size(s) (kW) and installation dates: 2000 kW June, 2001

1.3 Voltage of generator and grid interconnection: 4160

1.24 Fuel type(s): Diesel

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1	UNIT NO. 2	UNIT NO. 3	UNIT NO. 4
YEAR	ACTUAL HOURS	ACTUAL HOURS	ACTUAL HOURS	ACTUAL HOURS
2002				
2001	300	300	**300**	300
2000				

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? 20 years

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.).

Greenwood Utilities operates approximately 70 MWs of generation. Some coal, some natural gas turbine. Because of the extreme price fluctuation experienced in recent years, it was decided to add approximately 10 MWs of peaking generation. The work was a design build project. Ultimately, the equipment supplier became responsible for maintenance of the facility. To meet the emissions permit existing at the facility Selective Catalytic Reactors (UREA) is the agent) was used on three of the five diesel machines. A picture of this exhaust installation is attached.

4.0 How much time was required from project authorization completion?

Approximately eight months.

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)?

An existing Title V permit existed and it was amended. All other permits were already existing for the facility.

4.2 What was the approximate total installed cost of the project and cost per kW of net output?

$3,391,304

$339/kW

4.3 What is the average fuel cost per kWH? $0.046 per kWH

4.24 What are the actual maintenance costs per kWH per month (or year)? $0.018 per kWH

East Mississippi – Henderson Natural Gas

1.0 Project name and location: Henderson Station-Peaking Generation – 1350 kW units

1.1 Generator type: (Combustion turbine or reciprocating engine) Reciprocating Engines

1.2 Size(s) (kW) and installation dates: 1350 kW, Aug.2001

1.3 Voltage of generator and grid interconnection: 4160

1.25 Fuel type(s): Natural Gas

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1	UNIT NO. 2	UNIT NO. 3	
YEAR	ACTUAL HOURS	ACTUAL HOURS	ACTUAL HOURS	ACTUAL HOURS
2002				
2001	1600	1600	**1600**	1600

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? 20 years

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.):

Greenwood Utilities operates approximately 70 MW's of generation. Some coal, some natural gas turbine and some diesel peaking units. Because of the extreme price fluctuation experienced in recent years, it was decided to add diesel peaking generation. As the diesel generation project was underway, Caterpillar offered to sell the Utility "field follow" engines at a reduced price to obtain operating performance records in the general ambient conditions of the area (near sea level, high humidity and high temperatures). The work was a design build project. Ultimately, the equipment supplier became responsible for maintenance of the facility. The plant is operated by Greenwood Utilities' own operating personnel. The units chosen for installation were nominally rated at 1250 kW but due to the availability of an abundant supply of fresh ground water for cooling, the rating was extended to 1350. All units have operated at the prescribed output levels. Caterpillar engineers at Lafayette, IN have carefully monitored these three units.

3.0 Please attach hard copy, digital pictures, or drawings of the completed project as completed and/or during construction phase. [X] (check if enclosed/attached)

4.0 How much time was required from project authorization completion? Approximately 3 months

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)? An existing Title V permit existed and it was amended. All other permits were already existing for the facility.

4.2 What was the approximate total installed cost of the project and cost per kW of net output?

4.3 What is the average fuel cost per kWH? $0.031/kWH

4.3 What are the actual maintenance costs per kWH per month (or year)? $0.018/kWH

Grant County PUD, WA

1.0 Project name and location: Randolph Road Diesel Farm

1.1 Generator type: (Combustion turbine or reciprocating engine) Reciprocating engine

1.2 Size(s) (kW) and installation dates: (20) 1.6 MW units

1.3 Voltage of generator and grid interconnection: 13.8 kV output stepped up to 115 kV

1.26 Fuel type(s): Diesel

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1		UNIT NO. 2	
YEAR	PLANNED HOURS	ACTUAL HOURS	PLANNED HOURS	ACTUAL HOURS
2002	200	150		
2001	804	40		
2000				
1999				
1998				
1997				
1996				

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? 20 yrs

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.).

design-build

4.0 How much time was required from project authorization completion? 3 months for design and construction to energization. Permits took longer

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)? Diesel facility: (1) temporary operating permit (less than 365 days) – 2 mos., (2) notice of construction – 6 mos., (3) air operating permit – not yet issued, (4) county conditional use permit (less than one year), (5) permanent CU 4 months permit

4.2 What was the approximate total installed cost of the project and cost per kW of net output?

$27 M

4.3 What is the average fuel cost per kWH? 7.5¢

4.25 What are the actual maintenance costs per kWH per month (or year)? 10.5 cents/kWH

South Plaines EC, TX

1.0 Project name and location: Hale Center Generator

1.1 Generator type: (Combustion turbine or reciprocating engine) Reciprocating

1.2 Size(s) (kW) and installation dates: 1.6 mW – loaded @1.3 mW, installed 6/2001

1.3 Voltage of generator and grid interconnection: generator – 480 V., intercon – 12,470 V.

1.27 Fuel type(s): diesel

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1		UNIT NO. 2	
YEAR	PLANNED HOURS	ACTUAL HOURS	PLANNED HOURS	ACTUAL HOURS
2002	200	168		
2001	100	42		
2000				
1999				
1998				
1997				
1996				

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? 5 years

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.). design & built in-house

SPEC had been sponsoring some D.G. applications for the last four (4) years in conjunction With Texas Tech University. Just used what we had learned.

4.0 How much time was required from project authorization completion? 6 mos

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)?

4.2 What was the approximate total installed cost of the project and cost per kW of net output? Approx. $260,000 $200/kw (based on loading 1.3 mW)

4.3 What is the average fuel cost per kWH? Average $.0456/kWHR range: (2001) .0654 to (2002) .0421

4.26 What are the actual maintenance costs per kWH per month (or year)? $.00758/kWHR

City of Waverly, IA

1.0 Project name and location: South generating plant

1.1 Generator type: (Combustion turbine or reciprocating engine) reciprocating engine

1.2 Size(s) (kW) and installation dates: we installed 6 – 2000 kW engines

1.3 Voltage of generator and grid interconnection:

1.28 Fuel type(s): diesel fuel

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1	**UNIT NO. 2**	**UNIT NO. 3**	**UNIT NO. 4**
YEAR	ACTUAL HOURS	ACTUAL HOURS	ACTUAL HOURS	ACTUAL HOURS
2002	71	76	90	75
2001	74	81	88	97
2000	116	119	110	114
1999				
1998				
1997				
1996				

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? 40 years

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.). The project was bid in several pieces: the building, 6 engines, switchgear and the piping and mechanical work to install the engine. The project was engineered by Associated Consultants. Waverly provided the wiring of all electrical connections.

4.0 How much time was required from project authorization completion? 2 years

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)?

4.2 What was the approximate total installed cost of the project and cost per kW of net output?

Total cost = $3,997,000

Cost per kW = $333/kW

4.3 What is the average fuel cost per kWH? $.058 per kWH generated

4.4 What are the actual maintenance costs per kWH per month (or year)? $,088 per kWH/yr

Arkansas River Power Authority, CO

1.0 Project name and location: Lamar CT Project #1

1.1 Generator type: (Combustion turbine or reciprocating engine) CT

1.2 Size(s) (kW) and installation dates: 4.2 MW (standby) 2/2001

1.3 Voltage of generator and grid interconnection: 4160 V

1.29 Fuel type(s): Natural Gas

2.0 How many hours per year were the generator(s) operated?

	UNIT NO. 1		UNIT NO. 2	
YEAR	PLANNED HOURS	ACTUAL HOURS	PLANNED HOURS	ACTUAL HOURS
2002	2000	5060	JAN-AUGUST STOP DUE TO HIGH GAS PRICES	
2001	2000	2000		
2000				
1999				
1998				
1997				
1996				

Note: If there are more than two (2) units, please copy this form and include additional information.

2.1 What is the expected project life? 30 yrs

2.2 Please provide a summary of how the project was implemented (complete turn-key design, design-build, design-bid-build, etc.). Turnkey

Purchased unit then solicited bidders and financing

4.0 How much time was required from project authorization completion?

3 yrs prototype project

4.1 What permits were needed and how long did it take to get each of them approved (i.e. emissions, water, waste water, interconnection, acoustical, zoning, storage tank, other)?

Existing plant – need construction permit

4.2 What was the approximate total installed cost of the project and cost per kW of net output?

$2.3 M

4.3 What is the average fuel cost per kWH? Gross 3.26¢/kWH

4.27 What are the actual maintenance costs per kWH per month (or year)? $16.70/run hour – labor 3.9¢/kWH $18.00/run hour includes oil, filters, etc.

B
COST DATA SHEETS

Blank Cost Sheet, Page 1

Electric Power Research Institute
Distributed Generation Study Costing Template

Instructions: *Costs are requested by three major categories: Acquisition Costs, Installation Costs, and Indirect Costs. There are also sub-categories. Please take several minutes to review the component costs of each of these major categories before beginning this template. Not all component costs will be applicable to your installation. Provide as much detail as is possible. However, in those circumstances where this is not possible complete the sub-category column and/or total cost column and check off which component items were included in the respective cost.*

Line Number (column 1)	Item (column 2)	Major/Minor Cost Component (column 3)	Component Cost $ (column 4)	Total Cost for Sub-category $ (column 5)	Total Cost Major Category $ (column 6)
1	1	**Acquisition Costs**			
2	a.	**Engine/Generator**			
3		1. Standard Engine/Generator controls complete			
4		2. Indicate if remote cooling is required, otherwise include all cooling *[Circle(indicate) cooling type]*			
5		3. Indicate if generator breaker (non-synchronizing) is included *[See **e.3** below for synchronizing]*			
6		4. Battery storage and charger			
7	b.	**Enclosure/Auxiliaries**			
7		1. Enclosure or building structure *[Circle which one!]*			
8		2. Sound attenuating walls/doors			
9		3. Inlet/outlet Sound attenuation			
10		4. Inlet/outlet dampers, controls			
11		5. Lighting			
12		6. Enclosure heater			
13		8. Black start small IC gen-set			
14	c.	**Fuel Systems**			
15		***Fuel storage (diesel or propane)***			
16		1. Day tank/pump/controls			
17		2. Vaporizer/pump (propane)			
18		3. Sub-base fuel tank/controls			
19		4. Remote fuel tank/pump/controls			
20		***Fuel supply (natural gas, coal bed or landfill gas)***			
21		5. Pipeline gate station or LDC service facilities, or well head system			
22		6. Piping and regulation system			
23		7. Pressure booster compression station			
24	d.	**Emissions Control System(s)**			
25		1. NOX			
26		2. CO			
27		3. Other			
28	e.	**Switchgear/controls**			
29		1. Automatic Transfer Switch/controls			
30		2. Soft loading utility paralleling switchgear/controls			
31		3. Generator and utility synchronizing breakers/controls			
32		4. Intertie protection relay			
33		5. Supervisory controls			
34		6. Generator transformer			
35	f.	**Initial Inventory**			
36		1. Spare parts			
37		2. Special tools			
38		3. Lubricant			
39		4. Coolant			
40		5. Other consumables *[Please no fuel]*			
41	g.	**Site Access**			
42		1. Land purchase/lease			
43		2. ROW purchase/lease			
44					

Blank Cost Sheet, Page 2

Line Number (column 1)	Item (column 2)	Major/Minor Cost Component (column 3)	Component Cost $ (column 4)	Total Cost for Sub-category $ (column 5)	Total Cost Major Category $ (column 6)
45	2	***Installation Costs***			
46	a.	**Site Preparation/placement**			
47		1. Excavation			
48		2. Foundation(s)			
49		3. Generator inertia block			
50		4. Underground conduits/piping			
51		5. Offloading and placement			
52		6. Landscaping			
53	b.	**Free-standing Enclosure**			
54		1. Sound attenuating walls/doors			
55		2. Inlet/outlet Sound attenuation			
56		3. Inlet/outlet dampers, controls			
57		4. Other HVAC			
58		5. Lighting/service electrical			
59		6. Battery storage and charger			
60		7. Black start (small IC gen-set)			
61	c.	**Fuel System(s)**			
62		1. Day tank/pump/controls			
63		2. Piping			
64		3. Pump/compressor electrical			
65		4. Controls			
66	d.	**Mechanical**			
67		1. Heat recovery piping			
68		2. Remote heat recovery equipment			
69		3. Waste disposal piping			
70		4. Remote radiator/cooling tower piping			
71		5. Electrical/controls			
72	e.	**Power Electrical**			
73		1. Generator to Switchgear/ATS			
74		2. Switchgear/ATS to bus			
75	f.	**Electrical, controls and low-voltage service**			
76	g.	**Permit Inspections for physical construction**			
77	h.	**Site Commissioning/Startup**			
78		1. Generator			
79		2. Switchgear/protection			
80		3. Controls and SCADA			
81		4. Power Pool Studies and Accreditation			
82		5. Other			
83					

Blank Cost Sheet, Page 3

Line Number	Item	Major/Minor Cost Component	Component Cost $	Total Cost for Sub-category $	Total Cost Major Category $
(column 1)	(column 2)	(column 3)	(column 4)	(column 5)	(column 6)
84	3	***Indirects***			
85	a.	**Project Engineering**			
86		1. Civil/structural			
87		2. Process			
88		3. Mechanical			
89		4. Electrical			
90		5. Controls			
91		6. Architectural/landscape			
92	b.	**Owner's project management**			
93		1. Administrative and overhead			
94		2. Legal			
95		3. Financing			
96		4. Utility interconnection studies			
97		5. Site permitting, certificate of need			
98		6. Site permitting, electrical/building/conditional use			
99		7. Site permitting, air emissions			
100		8. Construction management			
101	c.	**Other**			
102		1.			
103		2.			
104		3.			
105		4.			
106	4	***Project Cost Offsets***			
107	a.	**Customer Contributions (funds, land, other)**			
108	b.	**Vendor Considerations (credits, funds, contributions)**			
109	c.	**Utility Subsidiary Contributions/Consideration**			
110	d.	**Other**			
111					
112	5	**Total Project Costs**			

Anonymous Utility A

112	**5**	**Total Project Costs**			$1,900,000

Anonymous Utility B

1	***1***	***Acquisition Costs***			$723,009
2	**a.**	**Engine/Generator**		$605,681	
28	**e.**	**Switchgear/controls**		$117,328	
45	***2***	***Installation Costs***			$392,852
66	**d.**	**Mechanical**		$138,500	
72	**e.**	**Power Electrical**		$254,352	
84	***3***	***Indirects***			$416,196
85	**a.**	**Project Engineering**		$149,061	
92	**b.**	**Owner’s project management**		$16,716	
94		2. Legal	$9,347		
95		3. Financing	$7,369		
101	**c.**	**Other**		$250,419	
102		1. Bond Reserve	$146,500		
103		2. All other costs attributed to project+C75	$103,919		
112	**5**	**Total Project Costs**			$1,532,057

Anonymous Utility C

1	***1***	***Acquisition Costs***			$1,382,153
2	**a.**	**Engine/Generator**		$996,134	
28	**e.**	**Switchgear/controls**		$386,019	
45	***2***	***Installation Costs***			$155,355
66	**d.**	**Mechanical**		$155,355	
84	***3***	***Indirects***			$112,337
85	**a.**	**Project Engineering**		$107,671	
92	**b.**	**Owner’s project management**		$4,666	
99		7. Site permitting, air emissions	$4,666		
112	**5**	**Total Project Costs**			$1,649,845

Anonymous Utility D

1	1	*Acquisition Costs*			$466,437
2	a.	Engine/Generator		$341,457	
7	b.	Enclosure/Auxiliaries		$83,250	
28	e.	Switchgear/controls		$41,730	
45	2	*Installation Costs*			$169,320
72	e.	Power Electrical		$169,320	
84	3	*Indirects*			$71,172
85	a.	Project Engineering		$71,172	
112	5	Total Project Costs			$706,929

Anonymous Utility E

Cost Form not filled out

Anonymous Utility F

85	a.	Project Engineering		$10,000	
112	5	Total Project Costs	turnkey construction average cost per installation		$950,000

Anonymous Utility G

1	***1***	***Acquisition Costs***			$107,000
15		***Fuel storage (diesel or propane)***	diesel	$5,000	
19		4. Remote fuel tank/pump/controls	$5,000		
24	**d.**	**Emissions Control System(s)**		$60,000	
26		2. CO	$60,000		
28	**e.**	**Switchgear/controls**		$42,000	
30		2. Soft loading utility paralleling switchgear/controls	$10,000		
32		4. Intertie protection relay	$12,000		
33		5. Supervisory controls	$20,000		
45	**2**	***Installation Costs***			$179,000
61	**c.**	**Fuel System(s)**		$3,000	
62		1. Remote fuel tank, pump, controls(above/below ground?)	$3,000		
75	**f.**	**Electrical, controls and low-voltage service**		$150,000	
76	**g.**	**Permit Inspections for physical construction**		$1,000	
77	**h.**	**Site Commissioning/Startup**		$25,000	
112	**5**	**Total Project Costs**			$286,000

Anonymous Utility H

112	**5**	**Total Project Costs**			$165,000,000

Central Virginia EC

1	***1***	***Acquisition Costs***			$421,500
2	**a.**	**Engine/Generator**		$408,000	
28	**e.**	**Switchgear/controls**		$12,000	
34		6. Generator transformer	$12,000		
35	**f.**	**Initial Inventory**		$1,500	
45	***2***	***Installation Costs***			$42,000
84	***3***	***Indirects***			$42,610
92	**b.**	**Owner's project management**		$16,110	
98		6. Site permitting, electrical/building/conditional use	$250		
99		7. Site permitting, air emissions	$500		
100		8. Construction management	$15,360		
101	**c.**	**Other**		$26,500	
102		1. Isolation switch in utility grid	$20,000		
103		2. SCADA control & communication	$6,500		
112	**5**	**Total Project Costs**			$506,110

City of Fennimore

Cost Form not filled out

City of Garnett

1	***1***	***Acquisition Costs***			$805,040
2	**a.**	**Engine/Generator**		$634,650	
7	**b.**	**Enclosure/Auxiliaries**		$170,390	
84	***3***	***Indirects***			$56,500
85	**a.**	**Project Engineering**		$30,000	
92	**b.**	**Owner's project management**		$26,500	
95		3. Financing	$22,500		
99		7. Site permitting, air emissions	$4,000		
112	**5**	**Total Project Costs**			$861,540

City of Iola

1	***1***	***Acquisition Costs***			$200,000
2	**a.**	**Engine/Generator**		$200,000	
3		1. Standard Engine/Generator controls complete	$140,000		
4		2. Indicate if remote cooling is required, otherwise include all cooling *[Circle (indicate) cooling type]*	$60,000		
45	***2***	***Installation Costs***			$1,000
77	**h.**	**Site Commissioning/Startup**		$1,000	
78		1. Generator	$1,000		
112	**5**	**Total Project Costs**	$201,000	$201,000	$201,000

City of New Knoxville

1	***1***	***Acquisition Costs***			$200,000
2	**a.**	**Engine/Generator**		$200,000	
3		1. Standard Engine/Generator controls complete	$140,000		
4		2. Indicate if remote cooling is required, otherwise include all cooling	$60,000		
45	***2***	***Installation Costs***			$1,000
77	**h.**	**Site Commissioning/Startup**		$1,000	
78		1. Generator	$1,000		
112	**5**	**Total Project Costs**			$201,000

City of Owensville

Cost Form not filled out

City of Rock Falls

1	***1***	***Acquisition Costs***			$675,000
2	**a.**	**Engine/Generator**		$510,000	
3		1. Standard Engine/Generator controls complete	$400,000		
7		1. Enclosure or building structure	$100,000		
19		4. Remote fuel tank/pump/controls	$10,000		
28	**e.**	**Switchgear/controls**		$175,000	
32		4. Intertie protection relay	$20,000		
33		5. Supervisory controls	$5,000		
34		6. Generator transformer	$150,000		
45	***2***	***Installation Costs***			$55,000
46	**a.**	**Site Preparation/placement**		$45,000	
47		1. Excavation	$20,000		
48		2. Foundation(s)	$20,000		
49		3. Generator inertia block	$5,000		
61	**c.**	**Fuel System(s)**		$10,000	
62			$10,000		
112	**5**	**Total Project Costs**			$730,000

City of St. George

Cost Form not filled out

City of Wrangell

1	***1***	***Acquisition Costs***			$1,762,000
2	**a.**	**Engine/Generator**		$650,000	
7	**b.**	**Enclosure/Auxiliaries**		$43,000	
14	**c.**	**Fuel Systems**		$43,000	
20		***Fuel supply (natural gas, coal bed or landfill gas)***		$473,000	
24	**d.**	**Emissions Control System(s)**		$43,000	
28	**e.**	**Switchgear/controls**		$510,000	
45	***2***	***Installation Costs***			$210,000
	a. - d.			$60,000	in-house
72	**e.**	**Power Electrical**		$150,000	Contract
84	***3***	***Indirects***			$278,000
85	**a.**	**Project Engineering -** power engineers		$278,000	
112	**5**	**Total Project Costs**			$2,250,000

East Mississippi – Meridian

Cost Form not filled out

East Mississippi – Canton

Cost Form not filled out

East Mississippi – Henderson

Cost Form not filled out

Grant County PUD

1	1	***Acquisition Costs***			$21,494,945
2	a.	**Engine/Generator**		$15,600,000	
15		***Fuel storage (diesel or propane)***		$1,582,945	
24	d.	**Emissions Control System(s)**		$4,312,000	
45	2	***Installation Costs***			$3,414,265
46	a.	**Site Preparation/placement**		$2,535,680	
47		1. Excavation	$466,835		
49		3. Generator inertia block	$657,670		
50		4. Underground conduits/piping	$371,600		
72	e.	**Power Electrical**		$527,900	
77	h.	**Site Commissioning/Startup**		$350,685	
80		3. Controls and SCADA	$350,685		
84	3	***Indirects***			$355,600
85	a.	**Project Engineering**		$355,600	
89		4. Electrical	$355,6000		
112	5	**Total Project Costs**			$25,264,810

South Plaines EC

1	1	***Acquisition Costs***			$212,549
2	a.	**Engine/Generator**		$192,049	
28	e.	**Switchgear/controls**		$20,000	
41	g.	**Site Access**		$500	
42		1. Land purchase/lease LEASE	$500		
45	2	***Installation Costs***			$49,001
46	a.	**Site Preparation/placement**		$45,758	
61	c.	**Fuel System(s)**		$3,242	
62		1. Day tank/pump/controls BELOW GROUND	$1,800		
63		2. Piping	$1,442		
112	5	**Total Project Costs**			$261,550

City of Waverly

1	***1***	***Acquisition Costs***			$2,930,770
2	**a.**	**Engine/Generator**		$1,943,903	
7	**b.**	**Enclosure/Auxiliaries**		$388,988	
15		***Fuel storage (diesel or propane)***		$71,794	
28	**e.**	**Switchgear/controls**		$526,085	
45	***2***	***Installation Costs***			$831,361
66	**d.**	**Mechanical**		$309,433	
72	**e.**	**Power Electrical**		$5,842	
75	**f.**	**Electrical, controls and low-voltage service**		$516,086	
84	***3***	***Indirects***			$234,846
85	**a.**	**Project Engineering**		$234,846	
112	**5**	**Total Project Costs**			$3,996,977

Arkansas River Power Authority

Cost Form not filled out

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EPRI creates science and technology solutions for the global energy and energy services industry. U.S. electric utilities established the Electric Power Research Institute in 1973 as a nonprofit research consortium for the benefit of utility members, their customers, and society. Now known simply as EPRI, the company provides a wide range of innovative products and services to more than 1000 energy-related organizations in 40 countries. EPRI's multidisciplinary team of scientists and engineers draws on a worldwide network of technical and business expertise to help solve today's toughest energy and environmental problems.

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