Novel Distributed Generation Control and Dispatching System

Application Validation and Benefits Quantification

Technical Report

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Application Validation and Benefits Quantification

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Cosponsors
GTI, Inc.
1700 S. Mt. Prospect Rd.
Des Plaines, IL 60018-1804

Principal Investigator
W. Liss

Public Service of New Mexico
2401 Aztec NE
Albuquerque, NM 87107

Principal Investigator
E. Reyes

EPRI Project Manager
D. Thimsen

EPRI • 3412 Hillview Avenue, Palo Alto, California 94304 • PO Box 10412, Palo Alto, California 94303 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

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ORGANIZATION(S) THAT PREPARED THIS DOCUMENT

ONSITE Energy Corporation

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CITATIONS

This report was prepared by

ONSITE Energy Corporation
701 Palomar Airport Road
Suite 200
Carlsbad, California 92009

Principal Investigator
K. Darrow

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REPORT SUMMARY

This report describes a novel control and dispatching hardware/software system for distributed generation. The system allows the connection of multiple generators at a number of sites to a utility control and monitoring system for the purpose of providing peaking power for the utility. Using distributed generation for this purpose is a potentially cost-effective solution to localized power system constraints caused by the inability to increase power transmission into an area experiencing steady growth in local power demand.

Background

Within nearly every utility territory is a population of emergency generators that provide backup in the case of a utility power outage. These generators are essentially invisible to the utility system. They are typically separated from the grid by transfer switches and protection systems and only operate when there is a grid fault and for periodic brief tests. Individually, these emergency generators range from a few kilowatts to a few megawatts each, but collectively this population of emergency generators represents a multi-megawatt block of power that could provide a meaningful system contribution during peak periods.

Objectives

To demonstrate a novel control and dispatching hardware/software system for distributed generation.

Approach

The project team installed a control and dispatching system for distributed generation at the Lovelace Medical Center in Albuquerque, New Mexico and documented the system's operation.

Results

In 1997, Public Service Company of New Mexico (PNM) proposed an instantaneous baseload interruptible rate for customers with their own generating equipment and the ability to dispatch power to the grid within one minute. With the assistance of co-funding arrangements, Lovelace Medical Center, a full service hospital in Albuquerque, upgraded their generator control and protection systems to take advantage of the new rate plan. The new system control equipment was installed in March of 1999. Currently, Lovelace has an 800 kW gas-fired Waukesha system with heat recovery that is part of PNM's existing experimental incremental load interruptible rate. This experimental rate uses a call-in system for the utility to notify the customer to start their generator. Lovelace also has two 450 kW Cummins diesel emergency gen-sets that could increase their peaking capability under the new rate from 800 kW to 1,700 kW.

The system has undergone test interruptions and successfully completed a system interruption at the utility's request. Unexpected regulatory changes occurred during the project that

unfortunately eliminated the financial motivation for instantaneous utility dispatch. The system continues to operate successfully as a fully integrated generator control system for the hospital and for providing peak load support on notification from the utility under the old experimental rate.

EPRI Perspective

The distributed generation application demonstrated at the Lovelace Medical Center is an integrated control, communications, and paralleling system for electric utility customer on-site power generation that allows the utility to dispatch the customer's generation to meet utility needs for capacity and reserve. The system is capable of controlling multiple generator sites.

Keywords

Distributed generation
Virtual power plants
Peaking power

ABSTRACT

A novel control and dispatching hardware/software system for distributed generators was installed at a hospital in Albuquerque, New Mexico. The system allows the connection of multiple generators at a number of sites to a utility control and monitoring system for the purpose of providing peaking power for the utility. Two diesel standby generators and a natural gas-fired generator were so equipped at the hospital site for dispatch during peak demand periods. Using distributed generation for this purpose is a potentially cost-effective solution to localized power system constraints caused by the inability to increase power transmission into an area experiencing steady growth in local power demand.

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INTRODUCTION

This report describes a novel control and dispatching hardware/software system for distributed generation. The system allows the connection of multiple generators at a number of sites to a utility control and monitoring system for the purpose of providing peaking power for the utility. Using distributed generation for this purpose is a potentially cost-effective solution to localized power system constraints caused by the inability to increase power transmission into an area experiencing steady growth in local power demand. The specific project demonstration described in this study involves the connection of three generators at a hospital in the Albuquerque, New Mexico area to the local utility for dispatch during peak periods.

GTI, Inc. and EPRI, Inc. provided the principal funding for the demonstration project. GTI support was provided as part of a competitive solicitation for the demonstration of novel DG applications and systems. EPRI, Inc. provided support through a tailored collaboration with Public Service Company of New Mexico (PNM), the local utility company. PNM, who provided supplemental funding for the effort, initiated the project idea and solicited the participation of Lovelace Medical Center (LMC) to place their existing onsite generation under the control of the utility in exchange for capacity payments by the utility. *EN*CORP, Inc. is the developer of the control system hardware and software and was responsible for system design and installation. Onsite Energy Corporation provided overall project management and prepared this case study description. Both *EN*CORP and Onsite provided *in-kind* cost sharing for the effort.

In 1997, PNM proposed an instantaneous baseload interruptible rate for customers with their own generating equipment and the ability to be dispatched by the utility within one minute. Lovelace Medical Center, a full service hospital in Albuquerque upgraded their generator control and protection systems with the assistance of co-funding arrangements on this project in order to participate in the new rate. Currently, Lovelace has an 800 kW gas-fired Waukesha system with heat recovery that is part of PNM's existing experimental incremental load interruptible rate. This experimental rate uses a call-in system for the utility to notify the customer to start their generator. Lovelace also has two 450 kW Cummins diesel emergency gen-sets that could increase their peaking capability under the new rate from 800 kW to 1,700 kW.

The new system control equipment was installed in March of 1999. Computer monitoring software has been installed at the hospital, PNM, *EN*CORP and at Onsite Energy Corporation. The system has undergone test interruptions and successfully completed a system interruption at the utility's request. Unexpected regulatory changes occurred during the project that unfortunately eliminated the financial motivation for instantaneous utility dispatch. The system continues to operate successfully as a fully integrated generator control system for the hospital and for providing peak load support on notification from the utility under the old experimental rate. In addition, the installation was used by PNM and potential business partners to evaluate an unregulated business venture involving aggregation of distributed generation to provide peaking capacity on the competitive power market.

This report documents the case study for this application. Section 2 gives a background to the project. Section 3 describes the control system that was installed. Section 4 outlines the economic justification for the project as originally conceived. Section 5 gives a general justification for projects of this type. Section 6 gives conclusions.

The several PNM rates referenced are included in Appendix A. The detailed operations of the controls installed are described in Appendix B.

2 BACKGROUND

This section describes the internal structure for PNM at the time the project was initiated, their overall supply and demand balance, and the changes that are underway as a result of the state mandated electric industry restructuring. A brief background is also provided for the other participants: Lovelace Medical Center, *EN*CORP, and Onsite Energy Corporation.

Overview of PNM

PNM is a combined gas and electric utility serving about 1.2 million people in 100 communities all across the state of New Mexico. In addition to its retail gas and electric business, PNM also sells power on the wholesale market, operates a water utility in Santa Fe, New Mexico, and offers a wide variety of energy-related services. PNM provides retail gas and electric service to a large part of the state; however, over half of PNM customers are in the Albuquerque metropolitan area. Following the completion of this project, PNM announced a proposed merger with Western Resources, a diversified energy company with retail electricity service in Kansas and part ownership of a major natural gas pipeline company.

In January 1995, PNM reorganized into four strategic business units, each targeted at a specific part of the company's customer base.

- *Electric Services* serves about 325,000 retail electric customers in a large area of north central New Mexico, including the communities of Albuquerque, Santa Fe, Rio Rancho, Las Vegas, Belen and Bernalillo. PNM Electric Services also serves Deming in southwestern New Mexico and Clayton in the northeastern corner of the state.
- *Gas Services* delivers gas products and services. PNM acquired its natural gas business in 1985 when it purchased a natural gas retail distribution system operated by Southern Union as the Gas Company of New Mexico. Today, PNM Gas Services distributes natural gas to most of the major communities in New Mexico, including Albuquerque and Santa Fe. PNM provides gas services to about 400,000 customers, the majority of whom reside in the Albuquerque metropolitan area. The majority of gas sales are for residential heating. Therefore, nearly 50% of throughput occurs in the peak four-month winter period of November through February.
- *Bulk Power Services* manages PNM's generating and transmission assets to bring power to our New Mexico retail customers, and to the regional wholesale market, at competitive prices. PNM owns or leases a total net generation capacity of 1,506 MW. That generating capacity includes a 750 MW share of the 1614 MW San Juan Generating Station; 192 MW in the Four Corners Power Plant, also in northwestern New Mexico; and 390 MW in the Palo Verde Nuclear Generating Station, in Wintersburg, Arizona. Finally, PNM owns two smaller gas- and oil-fired plants, with a combined generation capacity of 174 MW, which are used

primarily for peaking and transmission support. Last year, 72 percent of PNM's power was fueled by coal, while another 27.8 percent was nuclear, and 0.2 percent was generated by gas and oil. The rapid growth in PNM's service area in recent years, together with long-term off-system sales contracts, have absorbed much of the excess generating capacity PNM had in the past. But off-system wholesale sales are still a significant part of the business, accounting for nearly a third of PNM's total KWh sales and about 15.8 percent of total revenues from energy sales last year.

- *Energy Services*, the fourth strategic business unit, is applying PNM's management experience and technical expertise to developing a variety of new, energy-related opportunities. Energy Services is working with the Federal Energy Management Program to reduce energy and water consumption in Federal buildings. They offer customers a variety of value-added services:
  - Facility and utility system audits.
  - Mechanical and lighting system retrofits
  - Building controls/metering
  - Load management/SCADA
  - Alternative generation and renewables
  - Alternative fueled vehicles
  - Management and operations of utility systems
  - A team effort to satisfy the energy needs of all federal agencies in New Mexico.

This was the organization at PNM at the time of the project initiation. *Electric Services* and *PNM Energy Services* business units jointly supported the project. While the *Electrical Services* business unit was looking for cost-effective solutions to its peak delivery constraints, the *PNM Energy Services* business unit was looking to gain expertise in designing and packaging control systems for customers and utilities throughout the Western U.S. market. The stated project goals from PNM’s perspective were as follows:

- Aggregate 100 MW of customer generation to alleviate peak-load constraints in Albuquerque area
- Overcome the utility stigma attached to customer generation/cogeneration
- Prove the control/interconnection scheme
- Prove the concept environmentally
- Sell the concept internally
- Develop a national business.

In response to the electric industry restructuring order, to be described later, PNM further reorganized during the project. This reorganization and its impact on the project are described in the next section.

PNM's retail electric sales have been growing at more than 4 percent per year through the 1990s, reflecting the rapid growth in population New Mexico has experienced in recent years. Since 1989, PNM Electric Services has added 31,000 new retail customers, while total retail electric sales have risen from 4,909,592 Megawatt hours in 1989 to 5,953,151 Megawatt-hours in 1994, an increase of more than 20 percent. System peak demand has also been increasing rapidly in recent years, from 1,006 Megawatts in 1989 to 1,247 MW this year. The 1995 record high, reached August 10, is nearly 5 percent above last year's record. This steady growth in demand for capacity and energy has created transmission constraints on the PNM system during peak periods. Environmental constraints and issues related to use of Native American lands have made it difficult for PNM to add to their existing transmission capacity. In addition, it is very costly for PNM to plan new transmission projects, and these costs have, in the past, not been recoverable when the project does not go through. Therefore, PNM is seeking innovative means to support peak transmission and distribution (T&D) capacity and reliability on their system.

There is very little cogeneration on the PNM system. According to PNM, there have been four projects, two of which are still operating, one has been shut down, and one, Lovelace Medical Center, has been converted to a peaking unit. The projects are as follows:

- Sewer plant using digester gas
- Hospital (Lovelace)
- University (Turbine project “Marginally acceptable”)
- State Penitentiary (turbine project – failed and was removed).

According to Onsite’s database of cogeneration projects, there are an additional six projects including two large projects at a mining complex and refinery, an additional university project, and three small, less than 100 kW systems at an industrial and two small commercial facilities.

Restructured Electric Industry Post 2000

The Electric Utility Industry Restructuring Act of 1999 (also called SB428) was passed by the New Mexico legislature in April 1999. The plan will create a competitive market for power generation, provide retail access for all customers, separate generation from transmission and distribution functions, and consider a plan for recovery of stranded utility assets. An interesting aspect of the situation in New Mexico is that PNM is the only investor-owned utility (IOU) based in the state. El Paso and Southwest (both based in Texas) serve some customers in the state. The schedule for deregulation is as follows:

- PNM must file a transition plan by March 2000 (actually filed May 31, 2000)
- The commission has until December 2000 to approve it
- Desert Star Western ISO to start operation January 2001.
- Retail access for all customers by January 1, 2002.

PNM has already made organizational changes to prepare for the new market structure. PNM has formed a holding company called Manzano Corporation. The T&D business and customer service will be split from power generation and power marketing to become wholly owned subsidiaries of new holding company – Manzano Corporation. PNM will provide electric and gas services in the restructured regulatory model. Manzano Energy Corp. will provide power generation, power marketing, and energy services.

PNM filed its "Roadmap to Competition" on May 31, 2000. The plan, required by the restructuring schedule, addresses changes PNM is proposing to meet the new competitive requirements. The PNM plan has the following features:

- **Standard Offer Service** -- PNM outlines their required Standard Offer Service for customers who "choose not to shop" with competitively priced energy on an annual basis. Standard offer pricing serves as the *price to beat* for consumers who want to comparison shop. PNM will offer a Standard Offer Service renewable energy option for those customers who are interested in this product.
- **Safety Nets for Small and Large Customers** – Standard Offer Service will be the power supply safety net available to all residential and small business customers who are eligible for Standard Offer Service. So, if a supplier defaults on a service agreement, the customer will automatically be switched to Standard Offer Service. Commercial and industrial customers too large to receive standard offer service, that have not selected a competitive supplier, or whose competitive supplier has not delivered contracted power, may receive transitional default service under PNM's proposal.
- **Comprehensive Customer Education** – PNM will conduct a communication program for customers to inform them of their choices of energy suppliers and how to choose a supplier. PNM's plan provides for customer service representatives to help customers with their choices. In addition, PNM will upgrade their website and provide links to competitive power suppliers' web sites, to facilitate communication between customers and new suppliers.
- **Electronic Customer Communications System** – PNM has formed a consortium with the vendor of its customer information system and two other New Mexico utilities that use the same software. By developing software modifications jointly, the three utilities are able to share the costs and reduce potential transition costs. Representatives from PNM, El Paso Electric, Texas-New Mexico Power, and Southwestern Public Service are working with the Consumer Affairs Division of the Public Regulation Commission to develop some initial customer communications.
- **Third-Party Oversight of Transmission System** – PNM will participate in Desert STAR, a third-party regional transmission organization (RTO) that will operate the transmission system throughout the southwestern United States. Desert STAR is scheduled to be in place by December 2001.
- **Transition and Stranded Cost Recovery** – Based on the requirements of the New Mexico Electric Utility Industry Restructuring Act, PNM will seek between 50 and 100 percent recovery of stranded costs from residential and small business customers and 100 percent recovery from all other customers. PNM has estimated $692 million in stranded cost investment. In the late 1980s and early-to-mid-1990s, PNM shareholders reduced the amount of stranded assets by about $500 million through write-offs and write-downs. Nuclear decommissioning costs are estimated to be $44 million. PNM proposes to recover these costs through a separate charge on all customers' bills. Transition costs are projected to be $46 million. By state law, transition costs are fully recoverable. The utility is also seeking a higher return on equity (14.01%) that reflects a riskier business environment.

- **Continued Utility Investment in Reliability** – Every year, PNM invests about $60 million to $80 million in the electric and gas delivery system. With adequate stranded cost recovery, PNM can continue to attract capital at reasonable rate.
- **Wholesale Power Competition** – PNM has expanded its wholesale power sales and trading efforts and is positioning itself to offer competitive power from its generating plants throughout the Southwest through Manzano Energy.

An unintended negative aspect of the changes that PNM is implementing to prepare for restructuring is that the key PNM personnel that developed the peak load aggregation concept (that is the focus of this report) have been transferred into the bulk power services area. Thus, the internal project champions are no longer in a position to promote the concept inside PNM.

Lovelace Medical Center

Lovelace Medical Center (LMC) is a 235-bed, full service hospital located in Albuquerque, New Mexico. The current Medical Center, completed in 1987, is also the corporate headquarters of Lovelace Health Systems, a multispecialty physician group practice, a full service medical delivery system, and a managed care organization. In 1990-1991, CIGNA Healthcare Corporation acquired Lovelace Health Systems. In 1999, Lovelace was ranked 11th out of the 100 best-integrated health care networks in the country, according to *Modern Healthcare* magazine.

When the new Medical Center was constructed, it included an 800 kW gas-fired Waukesha engine-driven cogeneration system. Heat was recovered for the steam system and a waste heat fired absorption chiller. PNM attempted to negotiate a deferral rate at the time, but the hospital elected to go ahead with the cogeneration project. In 1996, Lovelace signed a contract with PNM to shutdown the cogeneration system and go on a new Experimental Incremental Interruptible Power Rate (EIIPR). The hospital did a full financial analysis of operating the cogeneration system vs. going to the EIIPR; it was about a break-even proposition to shutdown and go on the experimental interruptible rate, but by shutting the cogeneration plant down they were able to reduce staff by three people yielding an additional $200,000 operating savings.

The Waukesha cogeneration system requires a warm start. They have to supply steam to keep it warm. They also must start it up and run it a minimum of 2 hours/day. They have an absorption chiller that only runs when the system is on. The Waukesha engine is in need of a $150,000 overhaul whereas the whole system can be replaced for $275,000 (net of $50K sale of the Waukesha). Therefore, they decided to replace the Waukesha system with a 1250 kW diesel gen-set. They want a true emergency back-up system that can take up load in 10 seconds to handle their increase in critical loads. (The Waukesha was a 1 hour interruptible resource.) The two existing 450 kW diesel generators can't handle the total equipment loads.

When the utility proposed the new instantaneous interruptible rate, the hospital planned to expand their participation from the 800 kW associated with the Waukesha system to include their two 450 kW diesel back-up generators on the program. This would have increased their program participation from 800 kW to 1700 kW. Participating in the demonstration project allowed them to upgrade their entire control system for less than they could have done independently. The

*EN*CORP hardware controls the entire system. The previous control system was ASCO and Allen Bradley, some elements of which remain in the new system.

Details of the rate programs are provided in Section 4.

*EN*CORP and Onsite Energy

Aggregating customer generation to provide peak load power represents a new business opportunity for system developers and energy service companies. *EN*CORP and Onsite Energy both viewed the demonstration project as means of both evaluating and launching new business ventures.

*EN*CORP, Inc. is a privately held technology developer based in Windsor, Colorado. *EN*CORP manufactures and markets a complete line of advanced, utility-grade power controls and software systems targeted to switchgear manufacturers, gen-set dealers, integrators, engineering consultants, energy service providers, and utilities. *EN*CORP has developed and is now marketing a line of utility-grade generator power control systems that can provide single or multiple generator control, at one or more sites with remote interrogation and dispatch functions. Their *en*power™ control system and Virtual Power Plant™ software was the basis for the utility dispatch and hospital control system used in this project.

Onsite Energy Corporation is an independent, nationally accredited Energy Service Company (ESCO). Headquartered in Carlsbad, California, the company's initial focus beginning in 1982 was in cogeneration and onsite power project development in the very active California market. In more recent years, Onsite Energy has expanded both its geographical coverage as well as its product coverage – moving into all aspects of the energy service business. The company remains very active in distributed generation and combined heat and power, including project development and consulting services such as economic and market analysis, and strategic planning.

3 SYSTEM DESCRIPTION AND CONFIGURATION

The software and hardware system that was demonstrated in this project allows remote distributed generation systems to be combined and controlled from a central location. This section describes the underlying concept of the Virtual Power Plant and provides an overview and detailed discussion of the specific system demonstrated at the Lovelace Medical Center.

Concept of the Virtual Power Plant

Within nearly every utility territory is a population of emergency generators that provide for the customers' needs to protect themselves in the case of a utility power outage. These generators are essentially invisible to the utility system. They are typically separated from the grid by transfer switches and protection systems and only operate when there is a grid fault and for periodic brief tests. Individually, these emergency generators range from a few kilowatts to a few megawatts each. Yet taken as a whole, this population of emergency generators represents a multi-megawatt block of power that could provide a meaningful system contribution during peak periods.

The key components of the Virtual Power Plant System are shown in Figure 3-1. A Dispatch Center that is located at the utility site controls the system. Alternatively, a competitive power marketer or aggregator could take on the dispatch function. This entity would resell the aggregated power block as a peak resource to the regional or local grid system. The Dispatch Center is connected to any number of individual generators through **Control Processor Modules** (CPMs). The connections for the system can be made by a variety of communications media such as by secure phone line, Internet connection, radio or microwave transmission.

System Overview

The proposed distributed generation application is an integrated control, communications, and paralleling system for electric utility customer on-site power generation that allows the utility to dispatch the customer's generation to meet utility needs for capacity and reserve. The system is capable of controlling multiple generator sites.

A control system designed by *EN*CORP will be used in this application. The system consists of two subsystems the Utility Dispatch Center (Figure 3-2) and the Customer Generation Site (Figure 3-3). Additional description of these systems is provided below.

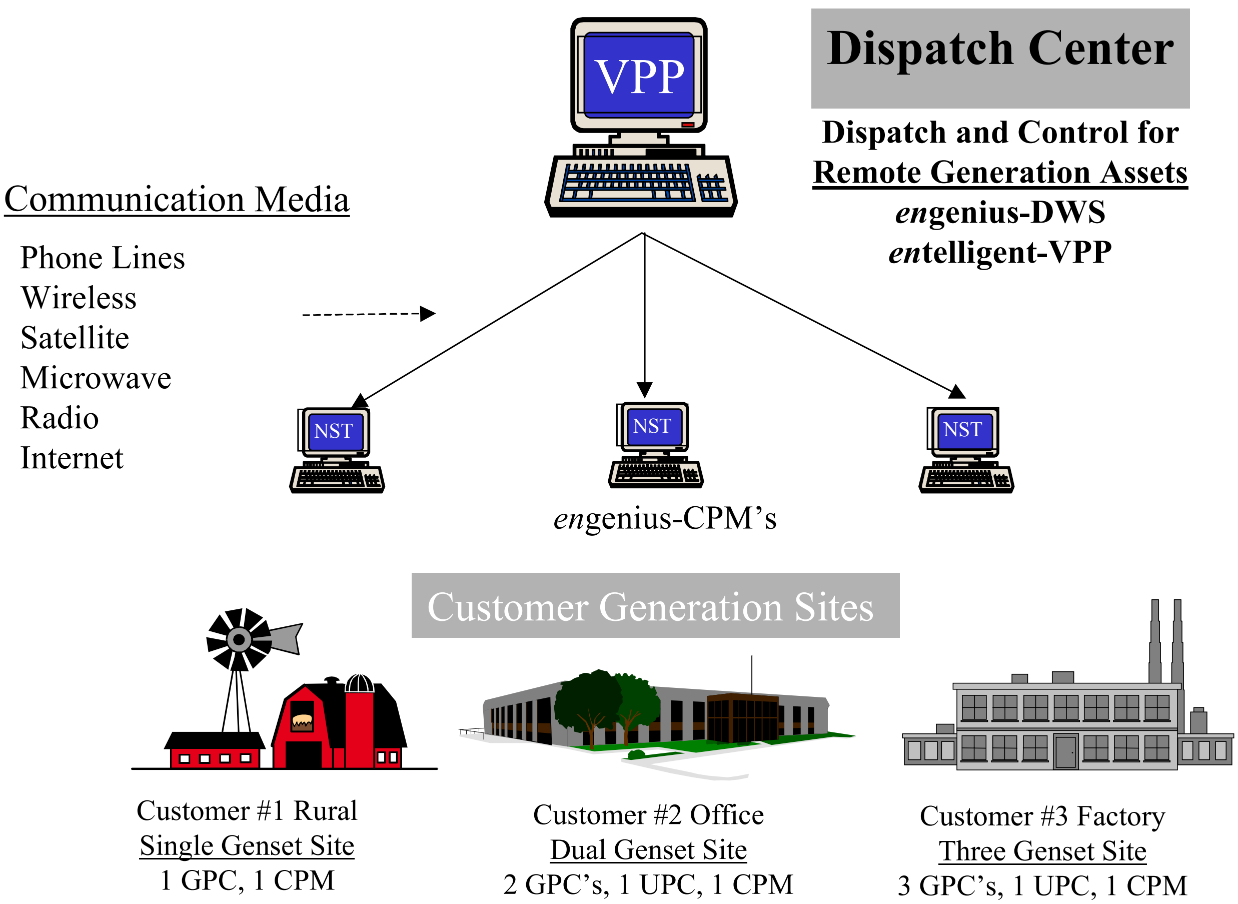

Figure 3-1
Virtual Power Plant™ System Concept

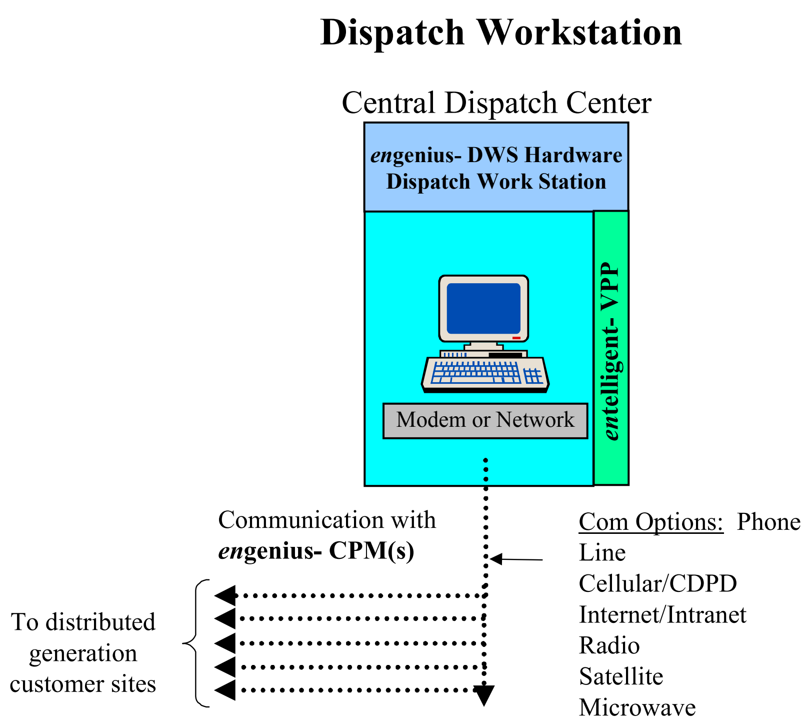

Figure 3-2
Dispatch Workstation Detail

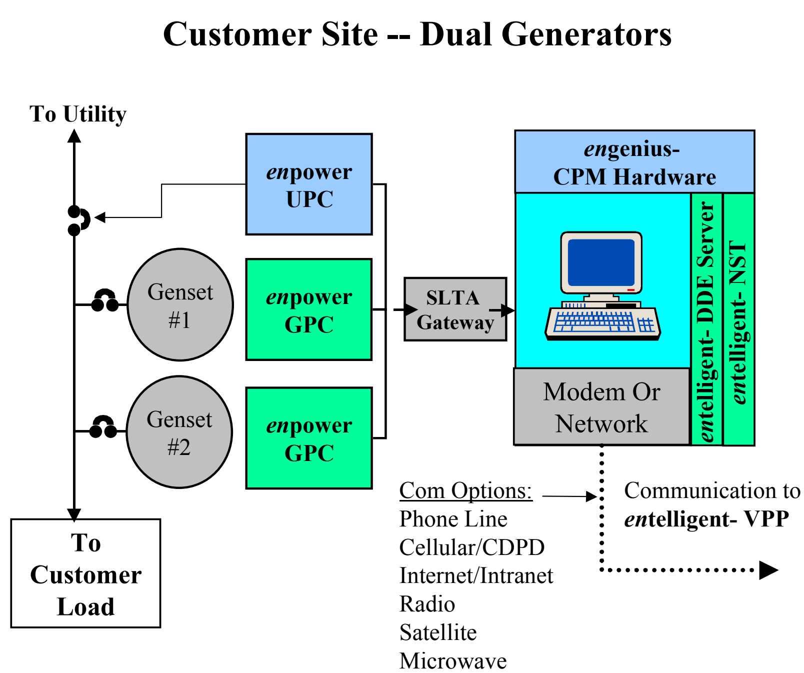

Figure 3-3
Customer Site Control Logic

Utility Dispatch Center

- DWS (Dispatch Workstation) – The DWS is an industrial grade Windows-based personal computer (PC) that contains a complete communications system used to dispatch and control remote generation assets.
- Dispatch software – The dispatch software is a powerful graphical user interface (GUI) designed to give the distributed generation user up-to-date information and real-time control over their remote generation assets.

Customer Generation Site

- CPM (Communications Processor Module) – The CPM is used to set-up the customer system; to provide metering, monitoring and control interface; and to communicate with the Dispatch Center.
- MMC (Meter/Monitor Control) – The MMC provides utility grade metering; monitoring and load shedding functions for direct load control and other deman-side management (DSM) programs.
- GPC (Generator Power Control) – The GPC provides complete generator control, protective relays, and remote dispatch and communications capabilities.
- UPC (Utility Power Control) – The UPC provides closed-loop control of the utility import/export power level, serving as a master synchronizer and control for two or more GPCs.

Protective Relaying Functions

- Sync check (25)
- Auto-synchronizer (25A) w/ voltage matching, two modes available:
  - Frequency and phase matching
  - Slip frequency
- Over/under voltage for generator and utility tie (27/59)
- Over/under freq. for generator and utility tie (81 O/U)
- Directional power (32)
- Directional reactive power (32VAR)
- Reverse-phase/phase-balance current (46)
- Phase sequence voltage (47)
- Voltage-restrained over-current (51VR)

Virtual Maintenance Monitor

The VMM serves as the Human-Machine Interface (HMI) for the system. The VMM is made up of several standard generator screens and a few custom screens based on the system configuration. The VMM can be used to quickly view breaker status, gen-set status, and power levels. The VMM allows the operator to monitor the respective gen-sets. The VMM is also used to adjust system parameters or configurations like the gen-set PT and CT ratios, protective relays trip levels, and other gen-set operating parameters. Selected interrogation screens of the VMM are shown below.

- The **Generator Overview Screen** shows the current generator information including voltage, current, kW, power factor and protective relay status. The user may select individual phases or 3-phase total/average metering. (Figure 3-4)
- The **Engine Overview Screen** shows current engine information, alarm & shutdown conditions, and maintenance & operations information. (Figure 3-5)
- The **Harmonics Screen** shows either voltage or current harmonics as part of an overall power quality control system.(Figure 3-6)

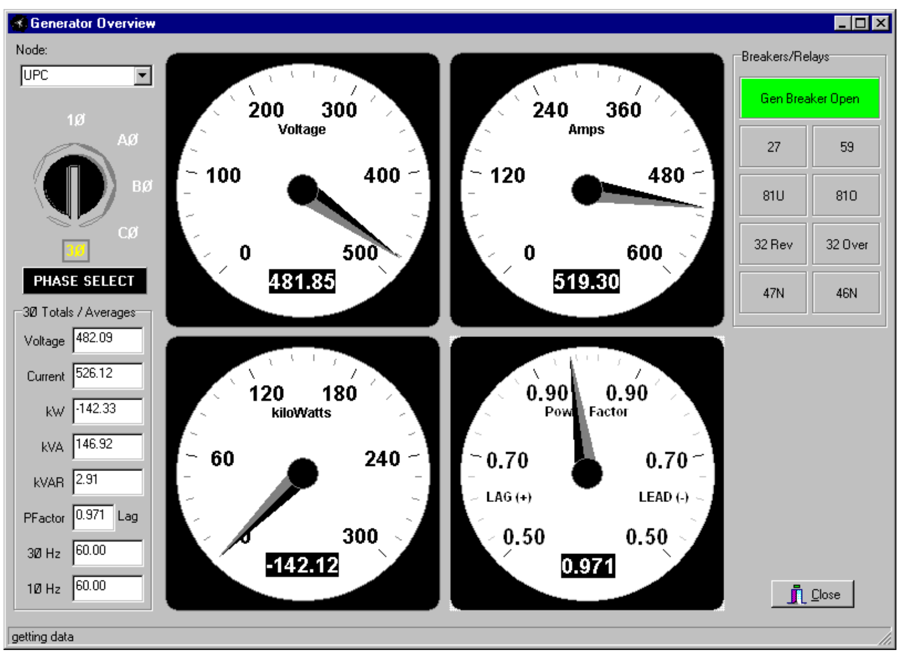

Figure 3-4
Generator Overview Screen of the Virtual Maintenance Monitor

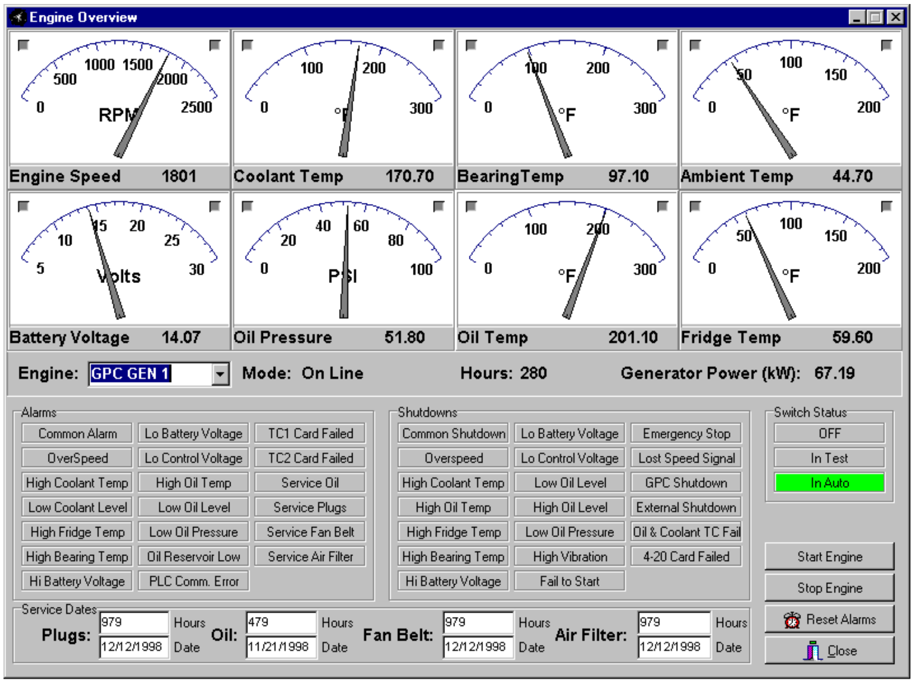

Figure 3-5
Engine Overview Screen

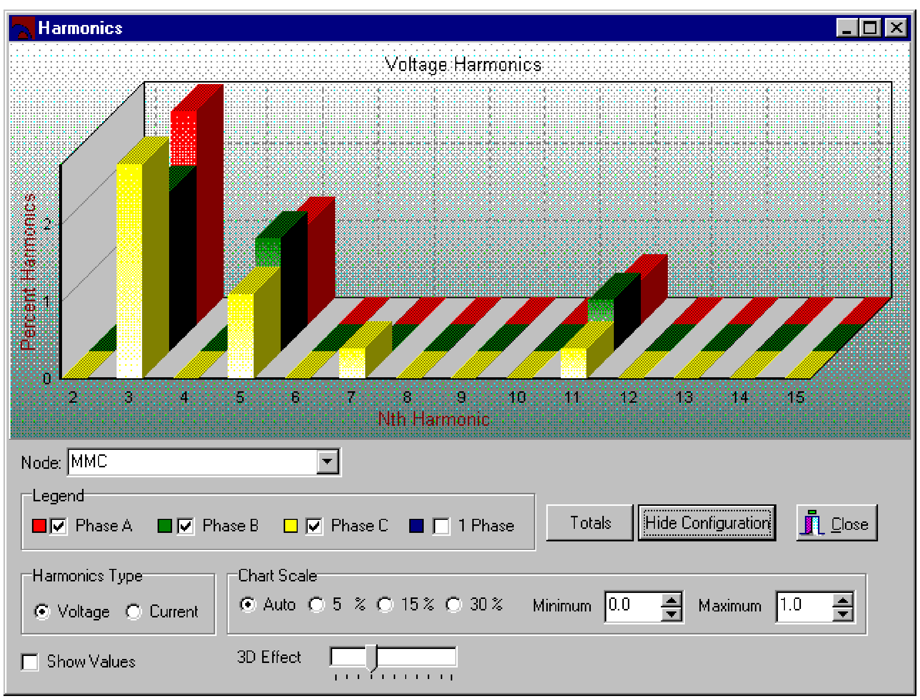

Figure 3-6
Voltage Harmonics Screen

Installation and Testing

The Lovelace Medical Center (LMC) has three generators for back up power, two Cummins (450 kW, diesel) and one Waukesha (800 kW, gas). As previously described, the gas-fired Waukesha unit was originally installed for combined heat and power (CHP) duty and was, therefore, interconnected in parallel to the PNM grid. The original switchgear was manufactured by ASCO in 1987. The ASCO Generator Control Panel (AGCP) was replaced with *EN*CORP Generator Power Controls (GPC). *EN*CORP also installed the Meter Monitoring Control (MMC) across the utility-tie breaker. The retrofit resulted in operations very similar to the original ASCO system with added remote monitoring capabilities. Because of the failure of the instantaneous rate to go into effect (See Section 4), LMC did not want to implement the capability of remotely dispatching the Generator Sets.

*EN*CORP staff performed the installation in March-April 1999. The installation required a number of adjustments to the software to allow seamless communication with the remaining portions of the original ASCO system. This debugging process continued for about a month as problems occurred in starting, synchronizing and holding the load. LMC installed a rental gen-set during the rewiring of the system.

In August, 1999, *EN*CORP personnel assisted in a hospital outage test and trained LMC staff in the new control system. The system functioned normally during this five hour test.

The installed system operations are described in detail in Appendix B.

Figure 3-7 through Figure 3-10 show photographs of the system following installation.

The new control hardware and software have provided Lovelace Medical Center with an updated control system that the hospital badly needed for their own purposes. Test interruptions have operated correctly. The system was utilized to interrupt the hospital during local substation work. All three on-site engines have been brought under control. The system was not interrupted by PNM as part of the experimental incremental interruptible power rate.

System Cost

Table 3-1 summarizes the equipment and installation costs for the system. The hospital equipment cost $85,050. It is important to note that this cost did not include interconnection with PNM as the Waukesha generator already had installed parallel operation capability and protective relays when it was installed as a CHP system. The utility control system cost $30,245. Of course, the utility system is designed to control a large number of individual sites, not just one as in this demonstration project. Finally, for the purposes of this study, two monitoring systems were installed at Onsite Energy and GTI. These systems would not be needed in a fully commercialized configuration, though there might be other requirements such as for power marketers, corporate energy offices, etc.

Figure 3-7
Two 450 kW Cummins Diesel Generators (Gen 1 and 2)

Figure 3-8
800 kW Waukesha Generator (Gen 3)

Figure 3-9
Generator Control Panels, External

Figure 3-10
Generator Control Panels, Internal, Showing ENCORP GPC unit (upper right)

Table 3-1
Equipment, Engineering, Installation, and Documentation Costs

Description	1997 Cost/Unit	Units	Total
Hospital Control System			
Generator Power Control (GPC)	$6,490.00	3	$19,470.00
Utility Power Control (UPC)	$7,725.00	1	$7,725.00
Communications Process Module (CPM)	$2,765.00	1	$2,765.00
Network Service Tool (NST) Software	inc.	1	inc.
Dynamic Data Exchange (DDE) Software	$1,050.00	1	$1,050.00
Serial Lon-Talk Adaptor (SLTA) Gateway	$785.00	1	$785.00
Engineering Services			$43,500.00
Documentation			$9,300.00
Shipping and Handling			$460.00
Hospital Total			$85,055.00
Utility Control System			
Dispatch Workstation	$5,280.00	1	$5,280.00
Virtual Power Plant (VPP) Software	$15,000.00	1	$15,000.00
Engineering Services			$5,400.00
Documentation			$4,500.00
Shipping and Handling			$65.00
Utility Total			$30,245.00
R&D Monitoring Stations			
Limited Function VPP (Monitor Only)	$7,500.00	2	$15,000.00
R&D Monitoring Total			$15,000.00

4
SYSTEM OPERATION AND BENEFITS

This section describes the evolution of PNM's interruptible rates and the economic operation of the system under a proposed rate specifically designed to aggregate customer capacity to contribute to the system peak load. A key feature of this new rate was to be the instantaneous dispatch (or interruption) of customer blocks of power. Due to the negotiations leading up to a transitional rate freeze, this instantaneous rate was never implemented. Therefore, the economics presented in this section are for information purposes only and do not describe the actual operation or benefits of the system today. The rates referenced here are included in Appendix A.

Development of Experimental Incremental Interruptible Power Rate (Rider 8)

Rider 8 "Experimental Incremental Interruptible Power Rate" (EIIPR) is an experimental rate originally developed in 1996 as a part of an economic development package that allowed customers with an incremental load to sign up for an interruptible rate if they would drop that load from the grid on-demand from PNM. The experimental rate was both load building and peak shaving. The rate encouraged customers to add new load to the system, but not add new peak demand requirements on the system. The rate was not open to customers to interrupt existing load. There are currently 20 customers offering a total of 17 megawatts under *Rider 8*.

The EIIPR was opened in 1996 to demand metered customers who could offer a minimum of 100 kW of incremental interruptible demand that can be interrupted within 30 minutes notice from PNM. A requirement of the rate is that "the customer would not have added the required level of incremental on-peak demand and energy in the absence of the rates provided in (Rider 8)." Interruptions are limited to 10 per calendar year, and no more than 3 interruptions and no more than 13 hours of interruption in any calendar month. Customers were required to sign a three-year initial contract to join Rider 8. Customers are billed up to their base level of demand according to their previously applicable rate tariff. The incremental interruptible demand (IID) will not incur a demand charge. The incremental energy is billed at a flat rate – from $0.045/kWh for substation voltage customers to $0.0612/kWh for secondary voltage customers. Customers that fail to meet a scheduled interruption are billed under their normally applicable rate schedule for the billing month in which the failure occurs. The existing Rider 8 is being revised. The revised EIIPR eliminates the restrictions on the number of emergency interruptions that PNM can implement each year.

Proposed Interruptible Rider 10B

In response to increased load and transmission constraints on the system, PNM proposed an expanded interruptible tariff that would be open to a wider class of customers. *Interruptible Rider 10B* had three interruption options for customers

- One-hour Interruptible Option (OHIO) – Available to customers within the Northern New Mexico Transmission boundary ($5.61/kW credit on interruptible demand per month with a $191 monthly implementation charge)
- Generation Only One-Hour Interruptible Option (GOHIO) – Available to customers outside of the Northern New Mexico Transmission Boundary ($3.75/kW credit on interruptible demand per month with a $191 monthly implementation charge)
- Instantaneous Interruptible Option (IIO) – Available to customers that allow PNM to control their interruption instantaneously ($7.89/kW credit on interruptible demand per month with a $713 monthly implementation charge).
- Under normal system operation, the customers on Rider 10B are limited to 400 hours/year of interruption. This level can be exceeded during system emergencies.

An IIO customer is able to save $94.68/kW per year less the implementation charge. Because of the high implementation charge for the IIO customer compared to the OHIO or GOHIO customer, this option only provides extra benefits to customers at levels of 300 kW and above. A 1000 MW IIO customer would save a net $86.12/kW per year.

It was envisioned that this rate would allow PNM to expand their experimental program and achieve over 100 MW of interruptible demand. The proposed new interruptible rate fell through during the final settlement negotiations of PNM's rate case in response to restructuring. PNM was offering an across the board average 7% rate reduction. However, the PUC wanted PNM to absorb all of the discounts resulting from the new interruptible rate. At approximately $50/kW with a 100 MW target this would have cost the utility $5 million per year. As a result, the proposed interruptible Rider 10B was not adopted.

Economic Analysis

The proposed economics for the LMC facility based on the hypothetical operation under interruptible rate *Rider 10B* are shown in

Table 4-1. The economics are based on 1,700 kW of contracted interruptible capacity and instantaneous dispatch. The instantaneous interruptible option (IIO) provides payments of $7.89/kW per month. The IIO carries a $713/month *implementation charge*. The net payments from the utility under the Rider 10B IIO for this project would have been $89.65/kW per year or $152,400 for the 1,700 kW available at the LMC site. Given the program costs of $130,000, the payback for the system is less than one year, and the total benefit over the life of the 3-year contract would be $327,200. Of course, the $130,000 program costs are not all borne by the hospital. In a commercial project, the hospital would only have to pay $85,000 or $50/kW. This amount does not cover interconnection costs.

Table 4-1
Hypothetical Economic Analysis based on Implementation of Rider 10B

Instantaneous Interruptible Option	
Contract Capacity (kW)	1,700
IIO- Credit ($/KW/month)	$7.89
Implementation Charge ($/month)	713
Project Benefit	
Total $	$152,400
Unit Benefit $/kW	$89.65
Control System Costs	
Hospital Control System	$85,000
Utility Control System	$30,000
Remote Terminals	$15,000
Total	$130,000
Payback	< 1 year
Net 3-year Benefit	$327,200

The approximate upgrade costs for dispatchable paralleling generation systems are $100-150/kW complete: switchgear, protective relays, controls (base load, import/export, VAR/PF, etc.), metering, communications, design, installation and startup. Where paralleling switchgear exists as in the LMC case, the costs would range from $40-100/kW for controls, communications, design, installation, and startup.

The general costs for the utility dispatch system would run from $15K to $75K for dispatch hardware/software plus $1,000 to $2,000 for each additional site. The Communications infrastructure varies from no cost for utilizing existing networks, $25 to $50/mo leased line/CDPD per site, up to $28,500 for dedicated licensed radio to cover entire the utility area (in one particular example).

The utility benefits are based on avoided generation and T&D costs, though PNM did not provide cost estimates for these benefits.

5
MARKET AND BUSINESS ANALYSIS

Part of the overall project work was to develop a market and business analysis of the Virtual Power Plant concept locally within the PNM service territory and to evaluate the applicability of the concept in other markets in the U.S. The failure of PNM to get approval for their instantaneous interruptible rate was a serious roadblock to expanding the concept locally. Without the rate approval there are no incentives for either the utility or the customer to proceed. Nevertheless, as part of an overall strategy of restructuring and evaluation of business opportunities, PNM did consider investing in the concept as a separate business venture with ENCORP and another partner. Due to the more pressing needs of the company-wide restructuring, PNM did not proceed. *EN*CORP is continuing to develop the market concept and technology with the help additional investors.

The intent of this section is to provide a basic appraisal of the concept, market potential, barriers, and potential strategies for the development of this market. This assessment is based on an appraisal of the underlying market and product match and on public statements made by *EN*CORP. It is not intended to reflect the internal business plan for *EN*CORP and other investors.

Market Concept

The demand for electricity varies hour by hour throughout the year depending on the aggregate needs of the electricity customers. With only very limited options for storage, the electric power industry must generate and deliver power on demand. For most utilities, 10-15% of total utility resources is needed for only 2-3% of the total hours in a year. This needle peak creates both economic and technical challenges for the power industry. Generation plants built to serve this load must amortize their costs over very few hours of operation per year, so the unit power costs are very high. In addition, the peak period creates bottlenecks in the T&D system.

This is not a new issue for utilities. However, the restructuring of the industry to accommodate wholesale and retail competition is making this problem much more visible and severely felt. Making competition available to electric customers is a way of allowing the benefits of competition among power generators to flow through to the customers. The initial evidence of the competitive market is that base load electric prices can be lowered considerably compared to the traditional imbedded cost pricing. However, the evidence of the 1999-2000 summers showed that the peak periods are producing very high price spikes and, in some cases, grid instability and even loss of load. Under the old regulatory framework, a utility could afford expensive solutions to peak power needs because the cost was rolled into the overall rate base. In the restructured environment, there is a need for both the electricity providers and the customers to protect themselves from peak period price spikes and reduced reliability.

One solution to meeting peak load is to deploy DG below the substation-level at or near the building load. If this were done with specially constructed DG facilities, that are generally more expensive than utility peak generation options, then the generation benefit goes away. In highly constrained areas, the T&D benefit could still be high enough to justify the project. However, the key to this concept that captures both the generation and the T&D benefit is to aggregate customer generation *that is already in place*. There is an estimated 60,000 MW of installed standby diesel-engine generator capacity in the U.S.

The Virtual Power Plant concept is to retrofit these existing standby systems with digital controls, communications, and grid interconnection equipment in order to aggregate their power output for very limited hours of operation per year. The retrofit/upgrade cost of $100 per kW or less compares very favorably with the cost of new peaking capacity. Since the generators are already in place, the key performance features of the system are as follows:

- Power metering,
- Remote Monitoring & Control
- Real-Time Economic Dispatch
- Power quality monitoring,
- Local and remote PC communications interface,
- Protective relays,
- Network communications and I/O expandability.

Market Potential

There are over 60,000 MW of installed diesel standby capacity in the United States. This capacity serves the emergency and standby needs of its owners – hospitals, factories, office buildings, etc. It is not considered part of the country's electric generation capacity. It is an insurance policy made up of, for the most part, silent iron. Although it is not counted as part of the nation's electric capacity, this stock of standby generators represents about 8% of the total power capacity in the U.S.

In addition, new diesel systems for the EPG (electric power generation) market are being added at a rate of about 23,000 units per year with a capacity of 6,700 MW. Approximately 12,000 units per year with a capacity of 4,250 MW are added in the key size range of 100 kW to 1,200 kW.

Looking at these numbers in the aggregate, it is clear that every major metropolitan area in the U.S. has between 100 and 400 MW of standby power that could be harnessed as part of the Virtual Power Plant concept. Developing Virtual Power Plant systems in 50 metropolitan markets in the U.S., each having an average capacity of 50 MW, would represent a 2,500 MW block of peaking power and a $200 million equipment market.

Market Barriers

There are a number of barriers that must be faced before the Virtual Power Plant can be widely accepted. The first barrier is utility cooperation and acceptance. The PNM example shows how difficult this can be. Even with a supportive development group, it was still difficult to enlist the support of the systems planning and dispatch functions of the organization. In addition, the benefits of the program to ratepayers as a whole were not adequately communicated in the regulatory process. In the rate settlement agreement, the program was seen as benefiting only the participating customers, when in fact, there were both a societal and nonparticipants benefit that could have been demonstrated.

Then there are potential emissions and permitting issues due to the use of diesel engines. Standby engines are generally permitted for emergency use and testing only. Some permits may not restrict the use but restrict the hours to less than 200 hours per year. To be effective, most of the programs would not require many more hours per year of operation. In fact, generally, the programs would be effective within the existing run-hour restrictions. However, if the concept really began to achieve significant market penetration, there would no doubt be pressure on the emissions and permitting side. One solution would be to undertake careful record keeping on run hours for standby engines. It is possible that system operations could take the place of periodic testing and thereby not contribute additional hours of use. A second possible solution involves converting the diesel engines to dual fuel (natural gas and diesel) operation. Approaches for dual fuel conversion have been technically demonstrated, but implementation to date has been limited.

High interconnection costs and a lack of standardization on interconnection represent a third significant market barrier. Interconnection requirements vary from utility to utility and the costs per unit of power, especially for systems less than 1,000 kW, can be very high. Part of the *EN*CORP concept involves compact, low cost paralleling equipment and protective relays. However, it is difficult and time consuming to re-engineer the system based on site-by-site requirements and to absorb the delays that currently exist due to the case-by-case review and approval process.

Of course, a VPP system could be implemented without parallel operation using a transfer switch that drops the customer load off of the grid. This approach, however, sub-optimizes the generating capability of the dispersed generators because they can only meet the load on those circuits that they serve. In addition, in isolated operation, the units must provide a reserve margin for safe operation and motor starting. A system operated in parallel with the utility could provide 100% of its rated capacity for peak load reduction whereas an isolated system might only be providing 30-50% of its nameplate capacity.

A final barrier is the transaction costs involved in identifying, contacting, and convincing customers to get involved. There is an inherently high effort that is involved in marketing this concept. In cases where a utility or an independent system operator (ISO) initiates a competitive request for proposals to provide peak power, it is very difficult to complete the customer identification and aggregation within the response period. There needs to be established utility or ISO programs with known participation costs and benefits so that the customers can be aggregated during a specific subscription period. While utilities themselves may not be the focus of marketing the concept, their cooperation is essential. They have the information on their customers, particularly customer generating equipment and facilities contacts.

Business Strategy

The value of the remote dispatch capability for customer-owned generating assets is difficult to market due to fragmented demand for the product and lack of established market channels. *EN*CORP is currently spearheading the VPP as a new application and configuration for controls hardware and software. They have active projects in a number of utility service areas. However, it is clear that the controls manufacturers will not be able to develop the market on their own. Due to the high marketing or aggregation costs, entities such as energy service providers (ESPs) and energy service companies (ESCOs) will need to take the lead in order for the concept to proceed past the demonstration phase. These companies have or can develop the manpower and expertise for customer contacts and utility interactions.

An obvious key starting point is a local electric utility company, ISO, or power marketer program that offers peak capacity payments. This enabling move is necessary to justify the aggregation. After all, a customer could use his system to provide added reliability and price protection on his own during peak periods, but this doesn't require the communication and control equipment that is being described in this project.

6
CONCLUSIONS

Under the proposed utility rate program, the hospital could have earned a net benefit of over $300K on a 3-year contract with a payback of about a year or less. However, the rate program became a casualty of a rate settlement agreement when interveners would not agree to allow the program costs to be recovered in the rate base. Consequently, there was no added incentive to the hospital to increase their participation from the 800 kW already on the experimental incremental interruptible power rate (EIIPR) to the full 1,700 kW capacity of the three generators at the site. Further, there was no incentive to operate with instantaneous notification and direct dispatch. From PNM's perspective, there was no incentive to add new interruptible customers and the opportunity to develop a cost-effective peak power program lost.

On the positive side, the project showed that the technical parameters of the system work. Customer protection has been demonstrated in a critical hospital environment. In addition, *EN*CORP and outside investors are continuing the development of plans for load aggregation and competitive marketing of peak power using the demonstration approach and technology.

A final conclusion is that utility avoided costs must be well characterized so the utility, customers, and regulators can all agree on program value. Also, utility system constraints can be transient so successful DG solutions must be low-cost to enable sufficient return on a short-term contract, flexible in location and operation, and/or serve a multiple function such as peak power support and standby power.

A
RATE CLASSIFICATIONS

PUBLIC SERVICE COMPANY OF NEW MEXICO - ELECTRIC SERVICES SCHEDULE 3B: GENERAL POWER SERVICE – TIME-OF-USE-RATE

(*EFFECTIVE* 5-26-96)

APPLICABILITY: The General Power Rate is available to all customers who use the Company's standard service for general power, lighting, and/or water and sewage pumping services and contract for a definite capacity commensurate with customer's normal requirements but in no case less than 50 kW or to customers whose consumption has exceeded 15,000 kWh per month or whose on-peak demand exceeds 50 kW per month for any three months in any 12-month continuous period. Service will be furnished subject to the Company's Rules and Regulations and any subsequent revisions. These are available at the Company's office and are on file with the New Mexico Public Utility Commission. These Rules and Regulations are a part of this Schedule as if fully written herein. The Company will establish guidelines for determining the method of selection of customers for service under this Schedule 3B by application of rules to be filed with the New Mexico Public Utility Commission.

TERRITORY: AU territory served by the Company in New Mexico.

TYPE OF SERVICE: The type of service available under this Schedule will be determined by the Company and would normally be either:

(1) 120/240 volt single-phase (overhead or underground), or

(2) 240 volt delta three-phase (overhead only), or

(3) Combination of *120/240* volt single-phase and 240 volt delta three-phase (overhead only; combined road not to exceed 75 kW; neither the single-phase nor the three-phase may exceed 50 kW), or

(4) 120/208 volt three-phase grounded Y from an overhead transformer (up to 125 kW),

(5) 120/208 volt three-phase grounded Y from a pad-mount transformer, or

(6) 277/480 volt three-phase grounded Y from a pad-mount transformer supplied at a single service location.

Note: 240 volt three-phase service is not available from underground distribution systems,

Refer to the Company's Rules and Regulations for further details pertaining to availability of these and other voltages and special service.

NET RATE PER MONTH OR ANY PART THEREOF FOR EACH SERVICE LOCATION:
The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) CUSTOMER CHARGE: $200.00/Bill

(Per Metered Account)
(Includes 1st 50kW of
Billed Demand)

(B) ON-PEAK DEMAND CHARGE: $4.00/kW
(For Billing Demand
Above 50 kW During
On-Peak Period)

(C) ENERGY CHARGE:

On-Peak Period (8:00 am --8 00 p m
Monday through Friday)
(60 hours per week)

Off-Peak Period (At all
Times Other Than On-Peak
Period) 108 Hours Per Week

For First 80 On-Peak kWh per kW Billing Demand per Month 13.1 l53¢/kWh

For next 120 On-Peak kWh per kW Billing Demand per Month 9.9000¢/kWh

All Additional On-Peak and all Off-Peak kWh per Month 4.3195¢/kWh

(D) TRANSFORMER OWNERSHIP CREDIT: For those customers receiving service at distribution (2,400 volt or higher) voltage and who supply their own transformers, the demand charge will be reduced by $0.30 per kW.

(E) POWER FACTOR ADJUSTMENT: For demands of 250kW and above a power factor of 90 percent or higher the Company will supply, without additional charge, a maximum of 0.48 kvar (Reactive Kilovolt Amperes) per kW of billed demand. The monthly bill will be increased $25 for each kvar in excess of the allowed 0.48 kvar per kW of billed demand.

(F) <u>SPECIAL TAX AND ASSESSMENT ADJUSTMENT</u>: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

<u>MONTHLY MINIMUM CHARGE</u>: The monthly minimum charge under this Schedule is the sum of the customer charge and the demand charge applicable to any monthly kW billing demand above 50 kW.

<u>TEMPORARY MINIMUM CHARGE</u>: Temporary or unusual service will be covered by the Company's Rules and Regulations and in such cases the minimum charges, conditions of furnishing substation equipment, connection and disconnection of service, and special conditions, will be covered by special agreement with the customer and the customer shall pay for all expenses involved in furnishing of the temporary service.

<u>DETERMINATION OF BILLING DEMAND AND CONSUMPTION</u>: This month kW billing demand shall normally be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand during the on-peak period but in no event shall it be less than the highest of the following: (a) the actual metered kW demand, or (b) 50 percent of the highest metered kW demand during the preceding 11 months, or (c) the contracted minimum kW demand.

Metering shall normally be at the secondary voltage; however, the Company reserves the right to meter customer's consumption at the available primary voltage, in which event the metered kWh, kW demand, and kvar shall be multiplied by 0.98 to allow for transformer losses.

For each service location the Company reserves the right to use either ~ single combination meter or a separate single- and a separate three-phase meter, in which event the demands will be added arithmetically and a single bill under the above rates will be rendered to the Customer.

Where highly fluctuating or intermittent loads which *are impractical* to determine properly (such as welding machine, electric furnaces, hoists, elevators, X-rays, and the like) are in operation by the customer, the Company reserves the right to determine the billing demand by increasing the 15-minute measured maximum demand and kvar by an amount equal to 65 percent of the nameplate rated kVA capacity of the fluctuating equipment in operation by the customer.

For water and sewage pumping only, the total kW demand, kvar demand, and kWh consumption for each type of like service (water or sewage pumping) shall be the arithmetic sum of these quantities measured at each service location as described above. In no case will the total aggregate billing demand be less than 50 kW nor less than the minimum specified in the customer's service application or contract with the Company.

<u>INTERRUPTION OF SERVICE</u>: The Company will use reasonable diligence to furnish a regular and uninterrupted supply of energy. However, interruptions or partial interruptions may occur or service may be curtailed, become irregular, or fail as a result of circumstances beyond

the control of the Company, public enemies, accidents, strikes, legal processes, governmental restrictions, fuel shortages, breakdown or damages to generation, transmission, or distribution facilities of the Company, repairs or changes in the Company's generation, transmission, or distribution facilities, and in any such case the Company will not be liable in damages. Customers whose reliability requirements exceed those normally provided should advise the Company and contract for additional facilities and increased reliability as may be required. The Company will not, under any circumstances, contract to provide 100 percent reliability.

ACCESSIBILITY: Equipment used to provide electric service must be physically accessible. The meter socket must be installed on each service location at a point accessible from a public right—of-way without any intervening wall, fence, or other obstruction (Ref. Rule 17).

TERMS OF PAYMENT: All bills are net and payable within twenty (20) days, and are delinquent thirty (30) days from the date the bill is rendered. If payment for any or all electric service rendered is not made within thirty (30) days from the date the bill is rendered, the Company shall apply an additional charge of 1 1/2 percent per month to the total balance in arrears, excluding gross receipts tax. Partial payment of amount due by Customer is applied first to oldest bill, including any other fees or charges assessed, if any, before any amount is applied to current bill.

TERMS OF CONTRACT: Service will be rendered under this Schedule for an initial contract period of not less than 12 months. Refer to Company's Rules and Regulations for information concerning terms and requirements of contract.

LIMITATION OF RATE: Electric service under this Schedule is not available for standby service and shall not be resold or shared with others.

PUBLIC SERVICE COMPANY OF NEW MEXICO . ELECTRIC SERVICES SCHEDULE 4B: LARGE POWER SERVICE--TIME..OF..USE RATE

(Effective 7-31-95)

APPLICABILITY The Large Power Rate is available to all customers who contract for a definite capacity commensurate with customer's normal requirements but in no case less than 500 kW of capacity. Service shall be furnished and metered at the Company's available distribution voltage. Customers with an estimated demand of 10,000 kW or more for any three months in a 12-month period will not be provided service under this schedule. Service will be furnished subject to the Company's Rules and Regulations and any subsequent revisions. These Rules and Regulations are available at the Company's office and are on file with the New Mexico Public Utility Commission. These Rules and Regulations are a part of this Schedule as if fully written herein. The Company will establish guidelines for determining the method of selection of customers for service under this Schedule 48 by application of rules to be filed with the New Mexico Public Utility Commission. Contracts for electric services to mines, oil and gas wells, refineries, mills processing mineral products, lumber and saw mills, or service to facilities of a similar type processing natural resources shall be for a specified time and shall require payment of a termination charge.

TERRITORY: All territory served by the Company in New Mexico

TYPE OF SERVICE: The service available under this Schedule shall be three-phase service delivered at the Company's available secondary distribution, primary distribution or transmission voltage. The delivery voltage of the Company will depend upon the capacity available and necessary to take care of customer's initial and contemplated future requirements, and the Company shall be the sole judge as to the voltage it can make available so as to provide for adequate capacity to the customer. Underground service is not available at transmission voltage. Underground service is available only in designated underground distribution system areas.

MINE, MILL, AND NATURAL RESOURCE SERVICE: The Company rates for electric service set forth in this Schedule are based on the assumption that service to all customer locations will be provided on a long-term basis. *Service* mines, *oil* and gas wells, refineries, mills processing mineral products, lumber and saw mills, or service to a facility of a similar type initially processing natural resources are placed in a special class due to the depletion of the natural resources supplying such facilities and consequent shorter term service requirements. Therefore the Company will provide service under this Schedule to such facilities only if the customer agrees to a specified period of service of not less than seven (7) years and to payment of liquidated damages in the event service is terminated prior to the end of the contract period of a sum determined by multiplying (a) an amount equal to the weighted average of the monthly peak period demand charge ($11.70 per kV\Q times the greater of (I) the customer's contracted minimum kW demand times the number of months remaining under the contract or (ii) 50 percent of the highest metered kW demand established during the preceding 11 months times (b) the number of months remaining under the contract. In cases of contract renewals, reinstatements, or movement from another rate schedule, the Company shall, where appropriate, include alternative liquidated damage provisions in the contract dependent on the cost to serve that particular Customer during the contract period. However, in no event will the alternative liquidated damage provisions exceed the otherwise applicable liquidated damage provisions under this rate.

Such payment will be due and payable within ten (10) days from the date service is suspended hereunder by reason of customers notification to Company that customer is suspending operations and desires that service be terminated. Customer will not be entitled to any electric service subsequent to the end of the contract period (or any extension) unless sixty (60) months prior to the end of the contract period, the customer has requested that the Company extend the contract for a period specified by the Customer. The Company will endeavor to permit a contract extension if the Company's load forecast indicates that adequate generating and transmission capacity will be available during the period specified by Customer. If the Company anticipates that there may be a shortage of generating capacity or transmission capacity during all or part of the period requested by customer, then Company will advise customer as to the period that customer may expect to receive firm service and will offer customer a contract for such period. All extensions must be in writing and executed as a supplement to the Agreement.

DISTRIBUTION EQUIPMENT: All distribution transformers, the necessary structures, voltage regulating devices, lightning arrestors, and accessory equipment required by the customer in order to utilize the Company's service shall be installed, paid for, and owned, operated, and maintained by the customer.

The customer shall also provide at his expense suitable protective equipment and devices so as to protect Company's system and its service, to other electric users, from disturbances or faults that may occur on customer's system or equipment. This must include a gang-operated switch located next to the metering installation and capable of interrupting the customer's entire load.

All such distribution equipment is to be installed by the customer and shall be of an approved design and shall conform to the Company's standards.

The customer shall at all times keep each of the three phases balanced as far as practicable so as not to affect service and voltage to other customers served by the Company. The customer shall not operate any equipment in a manner which will cause voltage disturbances elsewhere on Company's system. The customer shall at all times maintain a power factor of at least 90 percent.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION:

The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) CUSTOMER CHARGE: (Per Metered Account) (Includes 1st 500 kW of Billed Demand)	$5,850.00/Bill
(B) ON-PEAK PERIOD DEMAND CHARGE: (For Billing Demand Above 500 kW During On-Peak Period)	$11 .70/kW
(C) ENERGY CHARGE: For Energy Consumed During On-Peak Period: (8:00 a.m —8:00 p m Monday through Friday) (60 hours per week)	5.100¢/kWh
For Energy Consumed During Off-Peak Periods: (At all Times Other Than On-Peak Period) 108 Hours per Week	3.4000¢/kWh

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 90 percent or higher and the Company will supply, without additional charge, a maximum of 0.48 kvar (Reactive Kilovolt Amperes) per kW of billed demand. The monthly bill will be increased $25 for each kvar in excess of the allowed 0.48 kvar per kW of billed demand.

(E) DISTRIBUTION EQUIPMENT LEASE CHARGE: At the customer's option, the Company provides the distribution equipment described herein at a rate of $750.00 per month plus $1.50 per kW above 500 kW.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

MONTHLY MINIMUM CHARGE: The monthly minimum charge under this Schedule is the sum of the customer charge, the demand charge applicable to any monthly kW demand above 500 kW and the transformer lease charge if applicable.

DETERMINATION OF BILLING DEMAND AND CONSUMPTION: The billing demand for any month shall be as thus determined but in no event shall it be less than the highest of the following: (a) the actual metered kW demand, or (b) 50 percent of the highest metered kW demand during the preceding 11 months, or (c) the contracted minimum kW demand.

Metering shall normally be at the distribution voltage. The Company reserves the right to meter at the secondary voltage of customer's transformers, in which event the metered kWh, kW demand, and kvar shall be multiplied by 1.02 to allow for transformer losses. In the event the customer receives service at the transmission (46 kV or higher) voltage and is metered at transmission voltage, the metered kWh, kW, and kvar shall be multiplied by 0.98 to allow for transformer losses. Where highly fluctuating or intermittent loads which are impractical to determine properly (such as welding machine, electric furnaces, hoists, elevators, X-rays, and the like) are in operation by the customer, the Company reserves the right to determine the billing demand by increasing the 15-minute measured maximum demand and kvar by an amount equal to 65 percent of the nameplate rated kVA capacity of the fluctuating equipment in operation by the customer.

INTERRUPTION OF SERVICE: The Company will use reasonable diligence to furnish a regular and uninterrupted supply of energy. However, interruptions or partial interruptions may occur or service may be curtailed, become irregular, or fail as a result of circumstances beyond the control of the Company, public enemies, accidents, strikes, legal processes, governmental restrictions, fuel shortages, breakdown or damages to generation, transmission, or distribution facilities of the Company, repairs or changes in the Company's generation, transmission, or distribution facilities, and in any such case the Company will not be liable for damages. Customers whose reliability requirements exceed those normally provided should advise the Company and contract for additional facilities and increase reliability as may be required. The Company will not, under any circumstances, contract to provide 100 percent reliability.

ACCESSIBILITY: Equipment used to provide electric service must be physically accessible. The meter socket must be installed on each service location at a point accessible from a public right-of-way without any intervening wall, fence, or other obstruction (Ref. Rule 17).

TERMS OF PAYMENT: All bills are net and payable within twenty (20) days, and are delinquent thirty (30) days, from the date the bill is rendered. If payment for any or all electric service rendered is not made within thirty (30) days from the date the bill is rendered, the Company shall apply an additional charge of 1 1/2 percent per month to the total balance in arrears, excluding gross receipts tax. Partial payment of amount due by Customer is applied first to oldest bill, including any other fees or charges assessed, if any, before any amount is applied to current bill.

TERMS OF CONTRACT: Service will be rendered under this Schedule for an initial contract period of not less than 12 months. Refer to the Company's Rules and Regulations for information concerning terms and requirements of contract.

LIMITATION OF RATE: Electric service under this Schedule is not available for standby service, and shall not be resold or shared with others. Should the customer's demand exceed 10,000 kW for three months in any 12-month continuous period, the service will be transferred to Industrial Power Time-of-Use Service, Schedule SB.

PUBLIC SERVICE COMPANY OF NEW MEXICO . ELECTRIC SERVICES SCHEDULE 12: COGENERATION AND SMALL POWER PRODUCTION

(EFFECTIVE 3/11/99)

APPLICABILITY: The Cogeneration and Small Power Production Rate is available to qualifying cogeneration and small power production facilities which operate in parallel with the Company's system and which demonstrate Qualifying Facility (OF) status in accordance with Federal Energy Regulatory Commission (FERC) Rules and Regulations 18 CER Part 292, Subpart 13, Sections 292.201 through 292.207. This Schedule specifies the facilities and requirements for interconnection, the metering options available, energy purchase rates, the applicable rates and charges for services provided by the Company and the applicable Interconnection and Safety Standards. Service will be furnished in accordance with the Company's Rules and Regulations, the New Mexico Public Regulation Commission's (NMPRO) Rule 570 and any amendments or modifications thereto. These Rules and Regulations, the Company's retail rate schedules and Rule 570, as amended, are a pad of this Schedule as if fully written herein. These documents are available at the Company's offices and are on file with the NMPRC.

TERRITORY: All territory served by the Company in New Mexico.

TYPE OF SERVICE: The type of service for qualifying cogeneration or small power production facilities will be alternating current, generated at 60 hertz, single- or three-phase at one of the Company's standard primary or secondary distribution voltages. Single phase QEs may not exceed 10 KVA.

TERMS AND CONDITIONS: Service will be rendered under this Schedule upon submission of an Application for Interconnection by the QF, its acceptance by the Company and ultimate execution of an Interconnection Agreement which delineates the obligations of the OF and the Company, and upon completion of the interconnection of the OF to the Company's system.

ENERGY PURCHASES

ENERGY PURCHASE PAYMENTS: For a OF which wishes to contract for energy sales to the Company, the Company will offer rates based upon the average of the Company's economy energy purchases for the corresponding month of the preceding calendar year. In the event the Company does not engage in economy energy purchases in any given month, the energy rate for that month will be the monthly average of hourly incremental energy costs including variable operation and maintenance expenses.

A. Purchase Energy Costs By Costing Period

Period Purchase Energy Rate (in $ per kWh) for Residential, Small Power and General Power Rate Classes – secondary Voltage Level

1. Month	2. On-Peak[1]	3. Off~Peak[2]	4. Flat[3]
January	0.022989	0.015127	0.021045
February	0020143	0013053	0.016918
March	0021229	0.013628	0.018482
April	0.024824	0016712	0.021935
May	0021751	0011999	0020057
June	0.029006	0.013110	0.027178
July	0.046447	0.020335	0039973
August	0.053791	0.021695	0046915
September	0.047573	0020838	0.039831
October	0.026800	0018059	0.023412
November	0027756	0.017678	0023336
December	0028722	0016712	0.023716

B. Purchase Energy Rate (in $ per kWh) for Large Power and Water & Sewage Rate Classes – primary Voltage Level

5. Month	6. On-Peak[1]	7. Off-Peak[2]	8. Flat[3]
January	0 022603	0.014873	0.020692
February	0.019806	0.012834	0.016635
March	0.020874	0.01 3400	0.018172
April	0.024408	0.016432	0.021568
May	0.021386	0.011798	0.019720
June	0.028526	0.012894	0.026729
July	0.045678	0.019998	0.039312

August	0.052901	0.021336	0.046138
September	0.046776	0.020489	0.039163
October	0.026351	0.017756	0.023020
November	0.027290	0.017382	0.022945
December	0.028241	0.016432	0.023319

C. Purchase Energy Rate (in $ per kWh) for Industrial Power Rate Class. Substation Voltage Level

9. Month	10. On-Peak[1]	11. Off-Peak[2]	12. Flat[3]
January	0.022315	0.014684	0.020428
February	0.019554	0.012670	0.016423
March	0.020608	0.013229	0.017941
April	0.024097	0.016223	0.021293
May	0.021114	0.011648	0.019469
June	0.028166	0.012731	0.026391
July	0.045102	0.019746	0.038816
August	0052233	0.021067	0.045556
September	0.046180	0.020228	0.038664
October	0.026015	0.017530	0.022726
November	0.026943	0.017161	0.022653
December	0.027881	0.016223	0.023022

D. Purchase Energy Rate (in $ per kWh) for Government Contract Rate Glass. Sub transmission Voltage Level

13. Month	14. On-Peak[1]	15. Off-Peak[2]	16. Flat[3]
January	0.022123	0.014557	0.020252
February	0.019385	0.012561	0.016281
March	0.020430	0.013115	0.017786

April	0.023889	0.016083	0.021109
May	0.020931	0.011547	0.019301
June	0.027926	0.012622	0.026167
July	0.044718	0.019578	0.038485
August	0.051788	0.020887	0.045168
September	0.045781	0.020054	0.038331
October	0.025791	0.017378	0.022530
November	0.026710	0.017013	0.022457
December	0.027640	0.016083	0.022823

[1]On-Peak (Sam--S p.m. Monday-Friday) Only Energy Purchase Payments--Available to QFs whose generation is limited to peak periods only.
[2]0ff-Peak Only Energy Purchase Payments--Available to QFs whose generation is limited to off-peak periods only.
[3]Average Energy Purchase Payments--Available to QFs whose generation is not limited to peak periods only or off-peak periods only

OPERATIONAL CIRCUMSTANCES: In the event the Company disconnects and thereby discontinues purchases from a QF due to operational circumstances, the Company will notify the NMPRC and the affected QF in accordance with Section 570.29.

Actual discontinuance of purchases from QFs will take place only when such operational circumstances actually occur and not necessarily during periods when such conditions are expected to occur.

POWER SALES

SUPPLEMENTARY POWER: QFs are entitled to supplementary power under the same retail rate schedules that would be applicable to other retail customers of the Company having power requirements equal to the supplementary power requirements of the QF.

To determine the amount of supplementary power required, supplementary power will be measured to each QF through appropriate metering devices which are adequate to determine whether supplementary or backup power is being utilized. The Company reserves the right to determine the appropriate metering configuration.

BACKUP POWER: QEs are entitled to backup power for forced outages under the same retail rate which would be applicable absent its QF generation. Rates for backup power will not contain demand ratchets or power factor penalties.

The rates for backup power may contain a monthly reservation fee, not to exceed 10 percent of the monthly demand charge contained in the retail rate schedule (unless otherwise permitted by the NMPRC) which would be applicable to the customer absent its QF generation. Such a reservation fee will not be charged while a QF is taking backup power. Reservation fees are stated as per a kW charge. Monthly reservation fees are computed by applying the per kW charges times the demand which would be applicable absent QF generation.

MAINTENANCE POWER: Maintenance power rates will be the same as the retail rate which would be applicable to the QF absent its QF generation. The maintenance power demand charge will be determined by multiplying the applicable demand charge by the ratio of the number of weekdays maintenance power was required to the total weekdays in the month as summarized below. No demand charge will apply for maintenance power taken during the Company's off-peak hours.

$$\$\_\_/\text{kW times the ratio of } \frac{\text{Number of Weekdays in maintenance period}}{\text{Number of weekdays in the month}}$$

MAINTENANCE AVAILABILITY: Maintenance power will be available to QFs for a minimum period of thirty days per year, scheduled outside of the designated peak months of the Company.

MAINTENANCE POWER SCHEDULING

Maintenance power will be provided to QFs for periods of maintenance scheduled in advance with the concurrence of the Company. A QF must schedule such maintenance with the Company by giving the Company advance notice dependent on the length of the outage as follows:

Length of Outage*	Advance Notice
1 day	5 days
2 to 5 days	30 days
6 to 30 days	90 days

*All days are calendar days.

INTERRUPTIBLE POWER: The Company is offering an Experimental Incremental Interruptible Power Rate. Rider to qualifying Customers who can interrupt their incremental on-peak billed demand requirements. Eligibility requirements for this Rate Rider are detailed in Rider No. 8.

CUSTOMER CHARGE: The Customer charges from a utility for a QF shall be the same as the retail tariff rate applicable to the customers in the same rate class absent its QF generation.

NET RATE PER MONTH OR ANY PART THEREOF FOR EACH SERVICE LOCATION: The following peak period demand charges, peak and off-peak energy rates by rate class are applicable to supplementary, backup, maintenance, and interruptible power as specified in the preceding provisions of this Schedule. The Company's retail rate schedules as amended are part of this Schedule as if fully written herein, and must be referenced to determine applicable provisions specific to each Rate Class that are not explicitly provided in this Rate Schedule. This Rate Schedule does, however, contain exceptions to the application of the retail rate schedules to comply with the provisions of Rule 570 and must be applied as specified herein.

SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Charges billed under this Schedule may be increased by an amount equal to the sum of the taxes payable under the New Mexico Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state, and federal income taxes) levied or assessed by any governmental authority (on the energy produced by the QF or on the charges as billed by the Company, or on the right or privilege of either party rendering service, or on any object or event incidental to the rendition of the service). The QF, however, must honor the Company's nontaxable transaction certificate and not charge gross receipts tax on its sale of electricity for resale by the Company in the ordinary course of business,

TERMS OF PAYMENT: The Company will prepare a monthly billing statement itemizing all applicable charges due the Company for supplementary power, back-up power, maintenance power, and/or interruptible power and also itemizing all applicable credits due the QF for Energy Purchases. If the amount due the QF exceeds that due the Company a payment will be made to the QF. Otherwise the net balance due the Company is payable within twenty (20) days from date of bill and is delinquent thirty (30) days from date of bill. If payment for any or all electric service rendered is not made within thirty (30) days from the date the bill is rendered, the Company shall apply an additional charge of 1% percent per month to the total balance in arrears, excluding gross receipts tax. Partial payment of amount due by Customer is applied first to oldest bill, including any other fees or charges assessed, if any, before any amount is applied to current bill.

ATTACHMENT A – COGENERATION AND SMALL POWER PRODUCTION INTERCONNECTION FACILITIES AND REQUIREMENTS

INTERCONNECTION FACILITIES AND REQUIREMENTS: The QF will be required to pay the estimated costs of interconnection in full above the cost to provide standard service to the class to which the Customer would belong absent its QF generation facilities at the time the notice to interconnect is given. PNM's Interconnection and Safety Standards included in this Schedule contain detailed and specific interconnection and safety requirements.

OPERATION OF FACILITIES: Prior to interconnection the QF must supply the Company with a completed Application for Interconnection on a form supplied by the Company which must contain detailed electrical diagrams and other necessary data pertaining to the proposed QF and its protection systems for the Company's review and acceptance. The completed installation will be subject to a final inspection and test by the Company before parallel operation is permitted. The Company will determine satisfactory performance,

The QF must notify the Company prior to any modifications made to the QF or to the interconnection between the QF and the Company. The QF must receive approval from the Company prior to proceeding with such modifications. The QF must permit the Company, at any time, to install or modify any equipment, facility, or apparatus to protect the safety of its employees and insure the accuracy of its metering equipment. These costs will be borne by the QF.

The QF must ensure that the facility and all equipment connected therewith comply with the National Electrical Code, the National Electrical Safety Code, and/or any applicable local, state, and federal government requirements, whichever are stricter. For QFs with a design capacity greater than 10 kVA the QF must submit a statement from a Professional Electrical Engineer currently licensed in the state of New Mexico certifying that the design of the QF and its interconnection equipment complies with Company requirements and with reasonable interconnection safety and design standards and prudent electrical practices. The QF agrees to hold the Company harmless for any damage to person or loss to property arising out of the QF's failure to comply with such codes or legal requirements.

The QF must permit Company employees to enter its property at any time for the purpose of inspecting and/or testing the interconnection facilities to ensure their continued safe operation and the accuracy of the Company's metering equipment, but such inspection does not relieve the QF of the obligation to maintain the facilities in satisfactory operating condition,

LIABILITY: The QF will indemnify and save the Company and its agents and employees harmless from all liability and loss on account of injury or damage to persons or property resulting from any accident or mishap caused by the operation of the QF's equipment or by any failure of the QF to maintain equipment in satisfactory and safe operating condition.

ATTACHMENT B – COGENERATION AND SMALL POWER PRODUCTION METERING OPTIONS

METERING AND SERVICE FACILITIES: Billing for any power from the Company will be at the approved backup, supplementary, maintenance and/or interruptible rate applicable to the service provided to the QF. The Company may require such metering as is appropriate.

Metering options available to QFs are outlined below:

1. Load Displacement Option: The Company will interconnect with the QF using a single or three-phase metering arrangement which will be ratcheted to measure flow of energy to the QF. Billing to the QF will be at the Company's approved rate applicable to the service provided to the QF. There will be no additional customer charge and no payment by the Company for any excess energy which might be generated by the QF.

2. Net Metering Option: The Company will install appropriate metering to measure net energy consumed or supplied by the QF. The QF will be paid for energy supplied above the amount consumed at the energy purchase rate set forth in this Schedule.

3. Separate Load Metering (simultaneous buy/sell) Option: The Company will install an additional meter to measure separately all the energy produced and power consumed by the QF. The Company will purchase all energy produced at its energy purchase rate. The QF shall purchase all power consumed at its normally applicable rate.

The Company reserves the right to determine the appropriate metering configuration within each metering option. OFs will be served at one point of service (i.e., all meters will be physically located at one point).

ATTACHMENT C – APPLICATION FEE

APPLICATION FEE: At the time the Customer submits an Application for Interconnection on a form approved by the NMPRC, an application fee of $50.00 for qualifying facilities (OFs) with a design capacity of 100 kW or less and $500.00 for those OFs with a design capacity greater than 100 kW must be paid to the Company. Such application fee will be applied toward the interconnection costs the *OF is* obligated to pay the Company.

ATTACHMENT D – INTERCONNECTION AND SAFETY STANDARDS FOR OUALIFYING FACILITIES

Introduction

These Interconnection and Safety Standards have been prepared by Public Service Company of New Mexico (PNM) for those qualifying cogeneration and small power production facilities interested in operating in parallel with

PNM. The document has been separated into the following areas:

1. IMPORTANT CONSIDERATIONS FOR INTERCONNECTION.

2. GENERAL SAFETY REOUIREMENTS.

3. SPECIFIC INTERCONNECTION REOUIREMENTS.

IMPORTANT CONSIDERATIONS FOR INTERCONNECTION

A qualifying facility (QF) desiring to interconnect with the PNM system will be required to meet certain interconnection and safety standards. PNM will review the OF's interconnection design and will make corrective recommendations as necessary. PNMs interconnection and safety standards are designed to assure:

1 The integrity of the PNM system,

2. The quality of service to all PNM customers

3. The safety of PNMs employees and customers, and

4. The QF does not interfere with PNM's primary responsibility of providing safe and reliable electric service to all of its customers.

PNM will endeavor to aid and assist the QF in any reasonable way to insure the QF's interconnection design is adequate for connection of the OF to the utility system. This may include consultations with the QF and its engineering representative to coordinate the design, operation, maintenance, and protection of the PNM system interface with that of the QF.

The QF should allow adequate time in the design and construction schedule for design interface meetings with PNM and for material procurement by PNM. This time will vary depending on the QF's location, size, design, specific operating and system requirements, and the availability of materials needed to accomplish the interconnection.

All protection equipment associated with the interface, operational procedures, relay settings, and power transfer modes will be reviewed for acceptability by PNM. All interconnection equipment will be inspected and checked by PNM personnel authorized to accept the design and installation of the interconnection protection system.

If it is discovered that any equipment connected to the PNM system is in PNM's judgment problematic or is considered to be unsafe it will be disconnected from the PNM system.

QFs that generate electrical energy for on-site use only and are interlocked or otherwise prevented from feeding energy into the PNM system are special cases and may not be required to meet all of the requirements of this document. However, they are required to show by design and by operation that they cannot feed energy into the PNM system.

The QF design should include provisions to allow for the proper operation of the QF under unusual or adverse conditions. Conditions that should be considered are:

1. The sudden return of the utility system as a result of normal PNM system breaker operation.

2. Utility system transients (interference with normal utility system power flow, e.g., lightning and switching surges).

3. Manual disconnect operation by the utility (under emergency conditions the utility may need to disconnect the QF without prior notice).

GENERAL SAFETY REQUIREMENTS

The QF customer shall separate from the PNM power system in the event of

1. A fault on the QF's system.

2. A QF contribution to a PNM system emergency.

3. Abnormal frequency or voltage conditions on PNMs system.

4. Any occurrence or condition that will endanger PNM's employees or its customers.

5. A QF problem that would otherwise interfere with PNM's ability to provide safe and reliable electric service to other customers,

6. The sudden loss of the PNM system power

SPECIFIC INTERCONNECTION REQUIREMENTS

The specific interconnection requirements are the minimum requirements for QFs with a design capacity greater than 10 kVA. For QFs with a design capacity of 10 kVA or less, all of these requirements may not apply. However, each installation regardless of size, will be evaluated on a case-by-case basis.

All relays, current transformers, potential transformers, breakers, and interconnection power transformers shall be utility grade that meet or exceed the quality of the equipment that would normally be used by PNM in a similar application. The trip energy source for the interconnection breaker must be of a stored energy type (i.e., battery) that will be available under circumstances when the alternating current source is unavailable. The interconnection and all costs associated with the interconnection will comply with all relevant provisions of Rule 570, including Sections 570.8, 570.8 and 570.27.

The QF must ensure that the facility and all equipment connected therewith comply with the National Electrical Code, the National Electrical Safety Code, and/or any applicable local, state, and Federal government requirements, whichever are stricter.

The QF will be required to install at locations approved by PNM, the following:

1. A lockable, visible-open, load break disconnect between the QF and the PNM system that is visibly marked “QF Generation Disconnect.” This disconnect will be accessible to and lockable by PNM.

2. A fully rated breaker, that is visibly marked “QF Generation Breaker,” to isolate the QF’s generation from the PNM system in the event of a PNM system disturbance,

3. A permanent and weather proof one-line electrical diagram of the QF located at the point of service connection to PNM. A permanent and weather proof map of the QF showing the location of all major equipment including the PNM meter point, the QF Generation Disconnect, and the QF Generation Breaker, Included with or attached to this map will be the names and current telephone numbers of at least two persons that are authorized to provide access to the QF and who hove authority to make decisions regarding the QF interconnection and operation. This telephone listing shall be updated as needed to maintain its usefulness.

4. A synchronizing or synchro-check relay (for self-excited or self-commutated sources only) to provide for proper synchronization of the QF with the PNM system.

5. A frequency relay to disconnect the QF’s generation from PNM’s system under abnormal frequency conditions.

6. A set of voltage supervised directional overcurrent relays or impedance relays to disconnect the QF’s generation from PNM in the event of a fault on the PNM system. These are to be three-phase devices or three single-phase devices connected to sense the current in each of the three phases of the power system.

7. A voltage relay (three phase relay for three phase QF) to disconnect the QF's generation from PNMs system in the event of an abnormal voltage condition.

8. A QF Generation Breaker lockout or interlock to prevent the QF's generation from closing into or energizing any de-energized PNM power system equipment.

9. A directional, instantaneous, overcurrent relay or directional, instantaneous power relay to supervise and control the trip output of the voltage and frequency relays referred to above. These are to be three-phase devices or three single-phase devices connected to sense the current in each of the three phases of the power system. Single-phase QF interconnections will require only one relay to sense the current. However, it must be a directional relay.

10. QFs with a design capacity of 20 kVA or less may be required to have an isolation transformer if other customers are connected to the secondary side of the distribution transformer from which the QF is served. If a QF with a design capacity of 20 NA or less is the only customer connected to the secondary side of the distribution transformer, the QF may be required to have an isolation transformer when another customer is connected to the secondary side of the distribution transformer . When an isolation transformer is required, the OF will be required to install the isolation transformer at QF's expense. All QFs with a capacity larger than 20 kVA will be required to have an isolation transformer regardless of whether or not other customers are connected to the secondary side of the distribution transformer from which the QF is served. The power connections of these isolation transformers (wye or delta) will be determined by PNM.

    An isolating transformer shall not normally be required for single-phase photovoltaic systems rated at 10 WA or less which are interconnected to the utility grid by means of an inverter that satisfies the safety and performance requirements of state and local building codes, the National Electrical Code, Institute of Electrical and Electronic Engineers Standards and the National Electrical Safety Code. If, due to the particular configuration of the interconnection, PNM determines that an isolating transformer is required. and the customer disputes PNM's determination, PNM shall promptly file an Application with the NMPRC detailing PNM's technical justification for requiring an isolating transformer. The interconnection with the customer shall not be completed pending NMPRC resolution of the Application.

11. QFs sized at 5MW or larger will be required to interconnect with PNM at the subtransmission voltage level.

12. The maximum total QF capacity that will be allowed to interconnect with any PNM feeder is 60 percent of that feeder's power rating.

Additional PNM Interconnection Requirements

At the QF's expense and as necessary to protect PNM's system, PNM will install as determined on a case-by-case basis:

17. Additional protective relays to disconnect the QF generation or to trip the PNM substation breaker for QF system faults,

18. Additional breakers to isolate the QF's generation from the PNM system.

19. Any special relays or transfer trip equipment necessary to protect the PNM system from problems that are or may be caused by or are the result of the attachment to the QF. This may include but is not limited to high side potential transformers on the PNM substation transformer and the necessary relays and fault interrupters needed to clear PNM substation transformer or transmission line faults.

20. Special transformers needed for distribution ground fault sensing.

21. Dead-line supervised reclosing at the PNM substation.

22. Any modifications to the PNM system required to accommodate the QF to solve problems that are discovered after the QF is operational.

For QFs with a design capacity greater than 10kVA the QF installation and the electrical protection of the QF must be deigned or approved by a Professional Electrical Engineer engaged by the QF, currently licensed in the state of New Mexico. The details of the design, protection, operation and maintenance of the QF's equipment are the responsibility of the QF and its licensed Professional Electrical Engineer. PNM will accept the proposed QF interconnection design if it is adequate for interconnection with PNM's system. PNM's acceptance of the QF interconnection design shall not constitute PNM's agreement with the proposed QF's interconnection design relative to its completeness or its effectiveness for the protection of the QF.

Operating Requirements

1. Quality of Power:

   The QF is responsible for the quality of the QF power that is transmitted into the PNM system and is responsible for all damage that is caused by or that is a result of the QF's operation or the QF's connection to the PNM system.

   If other PNM customers are influenced or affected by flicker or harmonic distortion caused by the QF. PNM will require the QF to make changes to the facility to correct the problem. If such changes do not correct the problem or if the original problem is severe, PNM will require the QF to disconnect the disrupting machine or equipment from the PNM system until the problem has been resolved.

The maximum allowable voltage flicker (rapid change in voltage) caused by the QF is as shown below:

FREQUENCY OF VOLTAGE FLICKER	PERCENT OF VOLTAGE
1 per hour to 6 per hour	2.5%
7 per hour to 30 per hour	1.5%
31 per hour tad per minute	1.0%
7 per minute to 1 per second	0.7%
2 per second to 15 per second	0.6%

The above data is derived from charts and data in the Distribution Data Book by General Electric and from the Westinghouse Transmission and Distribution Book.

The total harmonic distortion of the QF voltage and/or current shall not exceed 5 percent of the fundamental 60 Hz frequency for the square root of the sum of the squares of the harmonics, and 2 percent of the fundamental 60 Hz frequency for any individual harmonic as measured at the customer service connection point.

2. Maintenance:

The QF owner is responsible for the maintenance and upkeep of the interconnection protection equipment. All interconnection protection equipment will be maintained on an annual basis. The OF may contract with PNM for maintenance services if desired.

PUBLIC SERVICE COMPANY OF NEW MEXICO - ELECTRIC RATES RIDER 8: EXPERIMENTAL INCREMENTAL INTERRUPTIBLE POWER RATE APPLICABLE TO RATE NOS. 36, 46, 56, 116,12 AND 40006

(EFFECTIVE 11-02-97)

EXPLANATION OF RIDER: Public Service Company of New Mexico (the Company) is offering an Experimental Incremental Interruptible Power Rate (EIIPR) Rider to qualifying Customers who can interrupt their incremental On-Peak billed demand requirements during the on-peak period. The Company's purpose in offering this Rider is to promote efficient and flexible utilization of the Company's generation, transmission and distribution capacity now and in the future.

This Rider is experimental and therefore the Company may petition to revise the terms and conditions of the Rider in the future to accommodate changing conditions and experience. Potential changes may include but not be limited to requiring participants to install direct load control equipment, reducing the response time to 10 minutes, or changes in the rates to reflect changing costs and requirements. All such changes will be submitted to the New Mexico Public Utility Commission (NMPUC) for approval with appropriate notice to Customers.

ELIGIBILITY: This Rider is available to Customers eligible for or currently being served under Rate Schedules 3B, 4B, 58, 118.12 (exclusive of backup and maintenance power, as those terms are defined in Schedule 12) or 40008 who also meet each of the following conditions:

1. Eligibility for this Rider requires a Customer to enter into a special contract with the Company for service under this Rider.

2. Eligibility for this Rider requires Incremental Interruptible Demand (IID) of at least 100 kW on average over the Base Period above the Base Demand, as described below, that can be interrupted within 30 minutes after notice from the Company. The Customer must show that it is probable that the Customer will achieve and sustain a specified level of IID by a date to be established in the contract for service under the Rider.

3. Eligibility for the Rider requires that the Customer provide the Company with evidence that the Customer would not have added the required level of incremental on-peak demand and energy in the absence of the rates provided in this Rider.

APPLICATION A Customer seeking to receive service under the Rider shall make written application to the Company and the Company shall review the Customer's eligibility for this Rider. The approval of all applications for service under the Rider shall be at the discretion of the Company in accordance with the provisions specified herein. If the

application is denied, the Company will provide the applicant with an explanation of the reasons for the denial of its application. If an applicant believes that it was improperly denied service under the Rider or if an applicant or current customer taking service under the Rider believes that the Rider has been improperly applied or discontinued, it may file a complaint with the NMPUC.

BASE PERIOD BILLING DETERMINANTS: Base Period billing determinants will consist of Average Base Demand, Peak Base Demand, On-Peak Average Base Energy and Off-Peak Minimum Base energy. These billing determinants shall be determined for each of the two PNM seasonal billing periods, the Summer period (June, July and August) and the Other period (all remaining months). The Average Base Demands shall be the 3-month average peak demand in the Summer period and the 9-month average peak demand in the Other period. The Peak Base Demands shall be the highest peak demand in the Summer period and the highest peak demand in the Other period. The On-Peak Average Base Energies shall be the 3-month average on-peak energy use in the Summer period and 9-month average on-peak energy use in the Other period. The Off-Peak Minimum Base Energies shall be the lowest monthly off-peak energy use in the Summer period and the lowest monthly off-peak energy use in the Other period. The On-Peak Average Base Energy and the Off-Peak Minimum Base Energy shall be normalized to daily averages and calculated each billing month depending on the number of days in the current billing cycle.

These billing determinants may be adjusted to reflect the Customer's normal operations as specified in paragraph 2 of the Contract section below, and may be adjusted to include any incremental demand and associated energy not designated as IID. To the extent that some portion of the Customer's incremental demand is not designated as IID, the Base Period billing determinants shall be specified in accordance with an analysis of the nature of the designated IID and its impact on the Customer's load profile that is acceptable to both the Company and Customer. For existing Customers, the Base Period shall be the 12 billing months immediately preceding the effective date of the contract for service under this Rider. Base Demand and Base Energy shall be zero for Customers with no billing history only to the extent that all incremental demand is designated as IID.

INCREMENTAL INTERRUPTIBLE DEMAND (lID):

1. IID is that portion of the Customer's monthly metered on-peak demand above the Average Base Demand that is served under this Rider. This also means that if the Customer's load grows and the Customer does not wish to interrupt this additional load, the Customer must notify the Company to adjust Base Period billing determinants accordingly. Such adjustments may require review and analysis by the Company. The Customer shall provide 60 days advance written notice of the need for such adjustments.

2. That portion of the Customer's IID load above the Peak Base Demand is subject to interruption during the Company's on-peak period with a 30-minute notice. The on-peak period is currently from 8:00 am, to 8:00 p.m. Monday through Friday including holidays. Interruptions will be made for two reasons: (i) for testing purposes: (ii) in the event of a PNM system emergency.

3. Interruptions for testing purposes will be made to test interrupting or monitoring equipment and the ability of the Customer to effect the required interruption.

4. Interruptions will be limited to 10 per calendar year. However, there will be no more than three (3) interruptions and no more than thirteen 13) hours of interruption in any calendar month.

5. For system emergency interruptions during on-peak periods, the Company will endeavor to interrupt participants receiving service under the Rider before interrupting or curtailing service to firm customers.

6. During the period of interruption the Customer's metered on-peak demand shall be no greater than the Peak Base Demand. Failure of the Customer to make the required interruption within the specified time for response shall cause the Customer's metered on-peak demand and energy to be billed under the normally applicable rate schedule for that month as described in paragraph 4 of the Rates Section below. In addition, future application of this Rider shall be discontinued if the Customer has failed to make the required interruption more than two times during any calendar year as requested by the Company.

7. In the event of an interruption under this Rider, the Company will endeavor to provide notices of interruption to all participants receiving service under the Rider at or about the same time, consistent with the interruption notification arrangements in place between the Company and the Customer.

<u>CONTRACT</u>:

1. The initial contract period for service under this Rider shall be up to three years. Thereafter, Customer contracts will be automatically renewed for subsequent one-year periods except under the following conditions: 1) no less than one year prior to the end of the existing contract period, PNM either gives written notice to the Customer that the contract will be terminated or that the contract will be renewed for a period of less than a year; or 2) no less than one year prior to the end of the contract period, Customer gives notice to PNM of its desire to renew the contract for a period of less than one year. However, in no case shall any contract extend beyond the life of the Rider. The Customer has the right to terminate the contract at any time by giving thirty (30) days written notice to the Company. For those contracts which are in existence at the time of any NMPUC action affecting the availability of service under this Rider, participants will continue to receive service under the Rider until expiration of such contract. In the event that amended terms and conditions of the Rider are approved by the NMPUC, participants' contracts will be subject to such amended terms and conditions.

2. IID shall exclude increases in billed demand resulting from resumption of normal Customer operations following a strike, fire, equipment failure, plant shutdown, or other interruption of operations in the Base Period. In the event that such an occurrence has taken place during the Base Period, the base period billing determinants will be adjusted to reflect normal operations.

3. The Customer shall be responsible for purchase, installation, and maintenance of all equipment or modifications necessary for the Customer to fulfill its interruption obligation. Such equipment shall include but not be limited to communication equipment such that interruption notification from the Company to the Customer can be reliably accomplished. Any special requirements regarding interruption notification procedures or equipment shall be specified in the contract for service under this Rider.

4. The contract may contain provisions concerning sub-metering of the lID portion of the Customer's load

TERRITORY: All territory served by the Company.

RATE RIDER LIMITS:

1. It is intended that the rates contained in this Rider shall be greater than or equal to the incremental cost of providing electric service to the customer. If the Company becomes aware that the continued offering of the Rider is detrimental to other existing Customers on the Company's system or that the rates contained in the Rider are no longer projected to be greater than or equal to the incremental cost of providing electric service to the Customer, the Company shall discontinue the availability of the Rider to new participants or petition the NMPUC for appropriate adjustments in the Rider. If the Company elects to discontinue the availability of the Rider, the Company will promptly notify the NMPUC of such discontinuance. If the Company discontinues the availability of the Rider, Customers with existing contracts will be given notice of non-renewal of such contracts but will continue to receive service under the Rider until the expiration of the existing contract period.

2. The Company reserves the right to deny a particular application of this Rider if in the opinion of the Company application of the Rider would be detrimental to other existing Customers.

3. This Rider is not available in conjunction with any other Rate Rider unless specifically provided for in the contract for service under this Rider.

DURATION: This Rider shall remain in effect until a new interruptible rate tariff is approved or the EIIPR is expressly discontinued whichever occurs first.

RATES:

1. All on-peak demand up to the Average Base Demand, the applicable system charge, the off-peak energy, and on-peak energy up to the On-Peak Average Base Energy shall be billed under the Customer's normally applicable Rate Schedule. Incremental On-Peak Energy above the On-Peak Average Base Energy (Incremental On-Peak Energy) associated with the IID will be billed as described below. There shall be no demand charge for IID except as specified below for non-compliance with the notice of interruption.

2. Incremental On-Peak Energy Rates

   Incremental On-Peak Energy Incremental On-Peak Energy shall be billed at a flat rate of $0612 per kilowatt-hour for secondary voltage, .05 per kilowatt hour for primary voltage level customers and, .045 per kilowatt hour for substation voltage level customers, unless the Load Shifting Condition is applicable.

Load Shifting Condition . A Load Shifting Condition applies whenever the Customer's off-peak energy drops below the Off-Peak Minimum Base Energy. Whenever this occurs, that portion of the Incremental On-Peak Energy that is equivalent to the decrease in off-peak energy below the Off-Peak Minimum Base Energy, shall be billed at $.08 per kilowatt hour.

3. As described in paragraph 6 of the Incremental Interruptible Demand Section above, Customers that fail to make their required interruption will be billed under the normally applicable rate schedule for the billing month in which the failure occurred. All demand and energy will be billed at the normally applicable rates; however, the lID portion of the total peak demand for that month will not be included in the calculation of minimum billing demand for subsequent periods.

4. All other terms and conditions of the applicable rate schedule for a specific Customer are incorporated herein to the extent such terms and conditions are not inconsistent with this Rider.

PUBLIC SERVICE COMPANY OF NEW MEXICO ELECTRIC SERVICES 4th REVISED RIDER NO. 8 CANCELING 3rd REVISED RIDER NO. 8

INCREMENTAL INTERRUPTABLE POWER RATE
APPLICABLE TO RATE NOS. 38, and 4B

Demands shall be the highest peak demand in the Summer period and the highest peak demand in the Other period. The On-Peak Average Base Energy shall be the 3-month average on-peak energy use in the Summer period and s-month average on-peak energy use in the Other period. The Off-Peak Minimum Base Energy shall be the lowest monthly off-peak energy use in the Summer period and the lowest monthly off-peak energy use in the Other period. The On-Peak Average Base Energy and the Off-Peak Minimum Base Energy shall be normalized to daily averages and calculated each billing month depending en the number of days in the current billing cycle.

These billing determinants may be adjusted to reflect the Customer's normal operations as specified in paragraph 2 of the Contract section below, and may be adjusted to include any incremental demand and associated energy not designated as IID. To the extent that some portion of the Customer's incremental demand is not designated as IID, the Base Period billing determinants shall be specified in accordance with an analysis of the nature of the designated IID and its impact on the Customer's load profile that is acceptable to both the Company and Customer. For existing Customers, the Base Period shall be the 12 billing months immediately preceding the effective date of the contract for service under this Rider. Base Demand and Base Energy shall be zero for Customers with no billing history only to the extent that all incremental demand is designated as IID.

INCREMENTAL INTERRUPTIBLE DEMAND (lID):

1. IID is that portion of the Customer's monthly metered on-peak demand above the Average Base Demand that is served under this Rider. This also means that if the Customers load grows and the Customer does not wish to interrupt this additional load, the Customer must notify the Company to adjust Base Period billing determinants accordingly. Such adjustments may require review and analysis by the Company. The Customer shall provide 60 days advance written notice of the need for such adjustments.

2. That portion of the Customers IID load above the Peak Base Demand is subject to interruptions which begin during the Company's on-peak period with a 30-minute notice. The on-peak period is currently from 8:00 am, to 8:00 p.m. Monday through Friday including holidays. An interruption may be extended up to two (2) hours into off-peak period, but the initial notice to the customer (the notice that an interruption will begin in 30 minutes) must have occurred during the Company's on-peak period. Interruptions will be made for two reasons: (i) for testing purposes; (ii) in the event of a PNM system emergency.

3. Interruptions for testing purposes will be made to test interrupting or monitoring equipment and the ability of the Customer to effect the required interruption.

4. Test Interruptions will be limited to 2 (two) per calendar year.

5. For system emergency interruptions which are called during on-peak periods, the Company will endeavor to interrupt participants receiving service under the Rider before interrupting or curtailing service to firm customers.

6. During the period of interruption the Customer's metered on-peak demand shall be no greater than the Peak Base Demand. Failure of the Customer to make the required interruption within the specified time for response or to maintain the required interruption shall cause the Customer's metered on-peak demand and energy to be billed under the normally applicable rate schedule for that month as described in paragraph 4 of the Rates Section below. In addition, future application of this Rider shall be discontinued if the Customer has failed to make the required interruption more than two times during any calendar year as requested by the Company.

7. In the event of an interruption under this Rider, the Company will endeavor to provide notices of interruption to all participants receiving service under the Rider at or about the same time, consistent with the interruption notification arrangements in place between the Company and the Customer.

<u>CONTRACT</u>:

1. Existing Customer contracts will be automatically renewed for subsequent one-year periods except as follows: no less than one year prior to the end of the contract period, Customer gives notice to PNM of its desire to renew the contract for a period of less than one year. However, in no event shall any contract extend past the initiation of customer choice for generation as provided for in the Electric Utility Industry Restructuring Act of 1999. The Customer has the right to terminate the contract at any time by giving thirty (30) days written notice to the Company. In the event that amended terms and conditions of the Rider are approved by the NMPRC, participants' contracts will be subject to such amended terms and conditions.

2. IID shall exclude increases in billed demand resulting from resumption of normal Customer operations following a strike, fire, equipment failure, plant shutdown, or other interruption of operations in the Base Period. In the event that such an occurrence has taken place during the Base Period, the base period billing determinants will be adjusted to reflect normal operations.

3. The Company will install and the Company shall be responsible for the cost of installation, and maintenance of alt equipment or modifications necessary for the Customer to fulfill its interruption obligation. Such equipment shall include but not be limited to communication equipment such that interruption notification from the Company to the Customer can be reliably accomplished. Any special requirements regarding interruption notification procedures or equipment shall be specified in the

contract for service under this Rider. Customers will provide and pay for dedicated phone lines as required.

4. The contract may contain provisions concerning sub-metering of the lID portion of the customer's load.

<u>TERRITORY</u>: All territory served by the Company. <u>RATE RIDER LIMITS</u>:

It is intended that the rates contained in this Rider shall be greater than or equal to the incremental cost of providing electric service to the customer. If the Company becomes aware that the continued offering of the Rider is detrimental to other existing Customers on the Company's system or that the rates contained in the Rider are no longer projected to be greater than or equal to the incremental cost of providing electric service to the

Customer, the Company shall discontinue the availability of the Rider to participants or petition the NMPRC for appropriate adjustments in the Rider. If the Company elects to discontinue the availability of the Rider, the Company Will promptly notify the NMPRC of such discontinuance. If the Company discontinues the availability of the Rider, Customers with existing contracts will be given notice of non-renewal of such contracts but will continue to receive service under the Rider until the expiration of the existing contract period.

<u>DURATION</u>: This Rider shall remain in effect until it is expressly discontinued or the initiation of customer choice for generation as provided for in the Electric Utility Industry Restructuring Act of 1999, whichever occurs first.

<u>RATES</u>:

1. All on-peak demand up to the Average Base Demand, the applicable system charge, the off-peak energy, and on-peak energy up to the On-Peak Average Base Energy shall be billed under the Customer's normally applicable Rate Schedule. Incremental On-Peak Energy above the On-Peak Average Base Energy (Incremental On-Peak Energy) associated with the lID will be billed as described below. There shall be no demand charge for lID except as specified below for non-compliance with the notice of interruption.

2. <u>Incremental On-Peak Energy Rates</u>

   <u>Incremental On-Peak Energy</u> – Incremental On-Peak Energy shall be billed at a flat rate of $.060237 per kilowatt-hour for secondary voltage, $049213 per kilowatt hour for primary voltage level customers and, $044292 per kilowatt hour for substation voltage level customers, unless the Load Shifting Condition is applicable.

   <u>Load Shifting Condition</u> - A Load Shifting Condition applies whenever the Customer's off-peak energy drops below the Off-Peak Minimum Base Energy. Whenever this occurs, that portion of the Incremental On-Peak Energy that is equivalent to the decrease in off-peak energy below the Off-Peak Minimum Base Energy, shall be billed at $.078741 per kilowatt hour.

3. As described in paragraph 6 of the Incremental Interruptible Demand Section above, Customers that fail to make their required interruption will be billed under the normally applicable rate schedule for the billing month in which the failure occurred. All demand and energy will be billed at the normally applicable rates; however, the IID portion of the total peak demand for That month will not be included in the calculation of minimum billing demand for subsequent periods.

4. All other terms and conditions of the applicable rate schedule for a specific Customer are incorporated herein to the extent such terms and conditions are not inconsistent with this Rider.

PUBLIC SERVICE COMPANY OF NEW MEXICO ELECTRIC SERVICES ORIGINAL RIDER NO. 10B INTERRUPTABLE RIDER APPLICABLE TO RATE *NOS. 3B, 4B, 5B, 11B, 30B, and 4000B*

EXPLANATION OF RIDER Public Service Company of New Mexico (PNM or the Company) is offering an Interruptible Rate Rider to qualifying customers who can interrupt all or pars of their load upon notification. The Company's purpose in offering this rider is to promote efficient and flexible utilization of the Company's generation, transmission and distribution capacity now and in the future.

This rider includes three options for Interruptible rates which are based upon the length of notification a customer requires prior to an interruption and the location of the customer on PNMs system as follows:

(1) ONE-HOUR INTERUPTABLE OPTION (OHIO): Customer will be given a one-hour notice for customer to lower demand to or below an agreed upon capacity level. This option is available to customers who fall within the Northern New Mexico Transmission Boundary. This corresponds to the FCN/SJN-WNM/ABQ transmission path as found in the Southwest Open Access Same-Time Information System (OASIS) This paths primary points of receipt are the Four Corners 230 kV Bus, the Four Corners 345 kV Bus, and the San Juan 345 kV Bus.

(2) GENERATION ONLY ONE-HOUR INTERRUPTIBI F OPTION (GOHIO): Customer will be given a one-hour notice for customer to lower demand to or below an agreed upon capacity level. This option is available to customers who fall outside the Northern New Mexico Transmission Boundary described in Option 1 above.

(3) INSTANTANEOUS INTERRUPLABLE OPTION (IIO): No notice **is** provided to the customer as PNM will control this interruption. The customers' demand on PNM's system must be lowered to or below an agreed upon firm capacity level. PNM will install control equipment, at the customer's expense, to insure that the customers interruptible load is atomically removed from the Company's

DEFINITIONS

PRICING PERIODS: For purposes of calculating charges under this rider, the daily time periods arc defined as On-Peak (8am to 8pm) weekdays and Off-Peak (all other hours).

STANDARD RATE SCHEDULE: The Company rate schedule under which a customer takes, or is qualified for, basic service without any rate riders or special conditions: Rate Schedules 32, 413. 52, I IB, 308 and 4000B.

IMPLEMENTATION CHARGE (OHIO, GOHIO): This implementation charge is designed to recover the standard costs associated with implementing this rider for metering, communication equipment, and services provided specifically for the individual customer. This charge is in addition to the Customer Charge under the customer's standard tariff Any additional costs incurred for customized implementation beyond the standard implementation will be billed to the customer.

IMPLEMENTATION CHARGE (IIO): This implementation charge is designed to recover the standard costs associated with implementing this rider for metering, communication equipment, and services provided specifically for the individual customer. This charge is in addition to the Customer Charge under the customer's standard tariff Any additional costs incurred for customized implementation beyond the standard implementation will be billed directly to the customer or incorporated into the FACILITIES CHARGE described below.

FACILITIES CHARGE (110): The facilities charge is based upon the specific facilities. including an RTU and installation required to supply an individual customer which are not applicable to any other customer. This charge also includes the cost of equipment at the customer site. The charge is the revenue requirement based upon the marginal cost of the dedicated facilities. The facilities charge also includes any additional equipment at the customer site that is necessary to implement this rider.

STANDARD TARIFF ADJUSTMENTS: These are adjustments to the customer's bill which are listed on existing Rate Schedules 3B 4B, 5B, 11B, 30B and 4000B. They include the Power Factor Adjustment, Distribution Equipment Lease Charge Fuel Adjustment, Transmission Service Credit, and Special Tax and Assessment Adjustment.

FIRM CAPACITY (FC). FC is the demand level that the customer agrees to be at or below once an interruption is in progress. interruptions will be based upon critical conditions on PNM's system. The minimum demand charge is based upon the FC.

A customer may have more than one interruptible option for load behind a single meter. If the customer elects such an option an interruptible}e hierarchy, as described below, is invoked and it is necessary for the customer to contact for a different EC for each level of the interruptible hierarchy.

CRITICAL CONDITIONS: A critical condition exists whenever the reserve margin on the Northern New Mexico transmission system drops below 40 MW, or the cost of purchased power exceeds the customer's tariff energy price, or when, in PNM's judgment, generation or transmission problems on the PNM System or in the WSCC threatens reliability.

SYSTEM EMERGENCY: A system emergency is any abnormal system condition which reduces PNM's ability to meet the service requirements of its customers. System emergencies require immediate manual or automatic action to prevent uncontrolled loss of firm load, equipment damage, or cascading outages of system elements.

INTERRUPTIBLE HIERARCHY. This applies only to situations in which a customer wishes to have more than one of the intenuptible options applied to load that is behind a single meter. This would not apply to interruptible loads behind separate meters. If a customer has more than one interruptible option behind a single meter, whenever an interruption of one option is called, all options having shorter notification tunes are considered to have been called. All interruptible options with more notification time are not considered to have been called unless the customer is informed otherwise

APPLICABILITY- This rider is available to customers currently on or qualified for service under Rate Schedules 3B, 4B, 5B, 11B, 30B, and 4000B. Customers must meet the following terms and conditions.

1. Customer must sign a special contract with PNM for service under this rider.

2. Under this rider, an interruptible customer must contract for firm capacity and have a minimum of 100 kW interruptible demand on average over the firm capacity it bar contacted for or be able to develop such load within the terms of a contacted time period not to exceed six months, The same PC is applicable in all TOU time periods for purposes of interruption. Given 30 days written notice, the customer may select a different firm capacity level at any time with the new selection effective on a prospective basis if the customer can demonstrate it is not shifting interruptible load to firm load. Further changes in the PC level will be accepted or rejected by PNM in its discretion.

If the customer no longer takes service under this rider or this rider expires or is terminated, the customer reverts back to taking service under its previous Rate Schedule 3B, 4B, 5B, 11B, 30B, or 4000B for which the customer is qualified.

TERRITORY: All territory served by the Company.

APPLICATION: Service under this Schedule will not be available until 30 days after the Company notifies the NMPUC that its new billing system is fully operational. A customer seeking to receive service under this rider shall make written application to the Company and the Company shall review the customer's eligibility for this rider. The approval of all applications for service under the rider shall be at the discretion of the Company in accordance with the provisions specified herein. If the application is denied, the Company will provide the applicant with an explanation of the reasons for the denial of its application. If an applicant believes that it was improperly denied service under the rider or if an applicant or current customer taking service under the rider believes that the rider has been improperly applied or discontinued, it may file a complaint with the New Mexico Public Utilities Commission (NMPUC),

NET RATE PER MONTH OR PART THERE OF FOR EACH SERVICE LOCATION: All credits/charges calculated by the application of the rates in this rider will be applied to the customers' bill for standard service as described in this rider.

(A) KW DEMAND CRFDITS FOR DEMAND IN EXCESS OF FIRM CAPACITY: The On-Peak period is from 8 am, until 8p.m. Monday through Friday (60 hours per week). The Off-Peak period consists of all times other than the On-Peak period (108 hours per week).

Rate Sched.	OHIO On-peak	GOHIC On-peak	IIO On-peak
3B:	($5.61)/kW	($3.75)/kW	($7 89)/kW
4B	($5.61)/kW	($3.75)/kW	($7.89)/kW
5B:	($5.61)/kW	($3.75)/kW	($7.89)/kW
11B	($5.61)/kW	($3.75)/kW	($7.89)/kW
30B:	($5.61)/kW	($3.75)/kW	($7.89)/kW
4000B:	($5.61)/kW	($3.75)/kW	($7.89)/kW

(B) IMPLEMENTATION CHARGE-OHIO AND GOHIO: $191 .00/Bill

(C) IMPLEMENTATION CHARGE- IIO $713.00/Bill

(D) FACITITIES CHARGE-IIO: Customer Contact defined above.

NON-COMPLIANCE:

During the period of interruption the Customers kW demand shall be no greater than the contacted Firm Capacity. Failure of the Customer to reduce kW demand to or below the contracted firm capacity within the specified time for response, regardless of when the interruption is called, shall cause the Customer's metered on-peak demand to be billed under the normally applicable rate schedule for that month. That is, if a customer does not comply with an interruption, which may be called at any time, no demand credit is given for that month. For example: If a customer's FC is 500 kW and the customer fails to comply with an interruption which is called at 1:00 am, the customer will be billed for all capacity used in the on-peak period at die full tariff rate.

Although customers that fail to make their required interruption will be billed under their Standard Rate Schedule for die billing month in which the failure occurred, the non-firm capacity portion of the total demand for that month will not be included in the calculation of minimum billing demand for subsequent periods.

If any customer fails to comply with three interruptions during the term of service under this tariff, the customer will be removed from this rider and returned co the appointee Standard Rate Schedule. The customer may reapply for service under this rider 12 months after the date of termination due to non-compliance. The Company, at its discretion, may grant the application but Is under no obligation to do so.

CALCULATION OF BILL:

1. Calculate the customer's monthly bill based on die Standard Rate Schedule then apply the following credits:

   a) If the FC is less than the actual maximum demand during a time period then the interruptible credit equals the actual maximum demand for the time period minus FC for the same time period multiplied by the appropriate interruptible kW Demand Credit from this Rider.

   b) If the EC is greater than other equal to the actual maximum demand during a time period, then the interruptible credit is zero.

2. Calculate Implementation Charges and Standard Tariff Adjustments.

MAXIMUM HOURS OF INTERUPTION: Normally, a customer shall not be curtailed for more than 400 hours a year as a result of this rider unless a System Emergency occurs. If customers on this rider have been interrupted for the full 400 hours and a System Emergency occurs, the customers on this rider will remain top priority for interruption; that is, the Company can exceed the "0"-hour interruption limit in case of a System Emergency. If a System Emergency occurs and the 400-hour limit has not yet been reached, the outage due to the emergency will be counted toward the 400-hour limit. Distribution outages are not included in the 400-hour limit.

There is no limitation on the number of interruptions per year or the length of interruptions. If actual interruptions have not occurred in the prior 4 months, the Company reserves the right to perform test interruption(s), any one of which will not exceed one hour. The outages due to test interruptions will be counted toward the 400 hour limit. In no event shall the Company be liable for any damages which the customer may incur as the result of any interruption.

CONTRACT: The contract period is for three years. Thereafter, unless one party or the other gives notice of termination two years prior to the end of the current contract year the contract is automatically extended by an additional year. The customer may switch service within options under this rider once during the contact period. Additional changes between options will be approved or rejected at the Company's discretion. If service is moved within options of this rider, the customer is still responsible for any contracted implementation or other outstanding charges incurred under the option it is leaving. All changes hi service roust be executed through a contract amendment. If the customer returns to the original tariff service under Rate Schedule 3B, 42, 513, 1113, 3Q13 or 400013, PN2vI reserves the right to preclude future service under this rider.

For those contacts which are in existence at the time of any NMPL:C action affecting the availability of service under this rider, participants will continue to receive service under the rider until expiration of such contact. In the event that amended terms and conditions of the rider are approved by the NMPUC, participants' contacts will be subject to such amended terms and conditions. In the event that changes are made to Rate Schedule 3B, 4B, 5B, 11B, 30B, or 4000B, those changes shall be made to any applicable calculations under this rider for which those tariffs are a basis.

RATE RIDER LIMITS: The company may petition to revise the terms and conditions of this rider in the future Co accommodate changing conditions and experience. All such changes will be submitted to the NMPUC for approval with appropriate notice to customers, It is intended that the rates contained in this rider shall be greater than or equal to the incremental cost of providing electrical service to the customer. If the Company becomes aware that the continued offering of this rider is detrimental to other existing customers on the Company's system or that die rates contained in this rider are no longer projected to be greater than or equal to the incremental cost of providing electrical service to the customer, the Company shall discontinue the availability of this rider. The Company will promptly notify the NMPUC of such discontinuance. If the Company discontinues the availability of this rider. customers with existing contacts will be given notice of non-renewal of such contracts but will continue to receive service under the rider until the expiration of the existing contract period.

The Company reserves the right to deny a particular application of this rider if, in the opinion of the Company, application of this rider would be detrimental to other existing customers or to the Company.

Except as stated herein, this rider is not available in conjunction with any other rate rider unless specifically provided for in the contact for service under this rider.

A customer may request alternate terms for die payment of bills (including pre-payment) that the Company will accommodate as possible.

B
LOVELACE MEDICAL CENTER: DESCRIPTION OF OPERATION

Introduction

The physical plant at the Lovelace Medical Center has three engine driven electrical power generators (Gen-sets):

- Gen-set 1 Cummins (Diesel) 450KW
- Gen-set 2 Cummins (Diesel) 450KW
- Gen-set 3 Waukesha (Natural Gas) 800KW

The three Gen-sets provide the site with emergency back up power in case the utility power fails. The Gen-sets can also be used to reduce the peak load requirements of the site. Gen-sets 1 & 2 can be baseloaded to reduce the utility requirements. Gen-set 3 can operate as a cogeneration unit to reduce the utility requirements. Other operating modes are available for Gen-set testing and/or exercising.

The original switchgear was installed in 1987 and was updated using the ENCORP *en*power hardware in March of 1999. The work preformed in March of 1999 was done in such a manner so the system functionality would remain unchanged. In addition to the original system functions, the following functionality was added:

- Remote system monitoring via a phone line
- Fuel level monitoring.

The following is a list of the major equipment that was added to the system:

- Generator Power Controls (GPC)
- Metering Monitoring Control (MMC)
- Communication Processing Module (CPM)
- Virtual Maintenance Monitor (VMM)

In addition to the major components listed above, several minor pieces of equipment were added including relays, terminal blocks, and miscellaneous wiring

Generator Power Controls (GPC)

The Generator Power Control is designed and manufactured by ENCORP and is part of the *en*power product family. One GPC was installed on each Gen-set and replaced the ASCO Generator Control Panels. The ENCORP GPC handles the functions preformed by the ASCO Generator Control Panel.

The GPC controls the power produced by the Gen-set via the Woodward 2301A LS&SC governor. The GPC operation is determined by the binding set (Software) loaded into the GPC. The binding set is the internal "Wiring" for the GPC software. The GPC software is made up of several virtual controllers and objects. These virtual objects are wired or bound together to create the custom application software for the site.

> **NOTE**: The GPC is capable of voltage (VAR/PF Control) control but those functions are not used in this application. The Basler VAR/PF control is used for VAR sharing and PF control and the related wiring has not been altered.

In addition to the binding software, the GPC has an embedded Programmable Logic Controller (PLC). The embedded PLC is a software package supplied to ENCORP by ISaGRAF. The ISaGRAF software allows the GPC to be used as a PLC in addition to its standard generator control software. The embedded PLC uses a ladder logic program to handle functions not available in the GPC virtual objects. The PLC code handles the following:

- Dead bus closing
- Engine mode selection
- Engine start timer
- Automatic/manual synchronizer
- Generator breaker trip logic.

Metering Monitoring Control (MMC)

The Metering Monitoring Control is designed and manufactured by ENCORP and is part of the *en*power product family. The MMC is installed across the utility tie breaker. The MMC senses the power flow through the utility tie breaker. The MMC is also used to monitor the diesel fuel tank levels. Two discrete inputs (High Level > 106% and Low Level < 6%) are used to monitor the day tank level and one discrete input is used to monitor the main fuel tank level (Level < 50%).

Communication Processing Module (CPM)

The Communication Processing Module is supplied to ENCORP by Cutler-Hammer. The CPM is a C-H D725 industrial computer. ENCORP loads the CPM with the *en*telligent software package. The CPM is the communications gateway for the system. The ENCORP products communicate to each other using the Echelon LonWorks network. The outside world can communicate to the LonWorks network via the CPM.

The LonWorks network is an open network designed by Echelon. The open network architecture allows additional LonWorks compatible devices to be added as the system grows and expands.

The CPM contains a modem, Ethernet Network Interface Card (NIC), LonWorks PCNSS card, I/O card, and a two channel serial communications card. Connected to the CPM, via the I/O card, is a keyboard, mouse, and monitor. This allows the CPM to be used as a local work station to monitor the Gen-sets and the modem provides the dial in access to monitor the system remotely.

Virtual Maintenance Monitor (VMM)

The Virtual Maintenance Monitor is a software package designed and manufactured by ENCORP and is part of the *en*telligent product family. The VMM serves as the Human-Machine Interface (HMI) for the system. The VMM is made up of several standard generator screens and a few custom screens based on the system configuration. The VMM can be used to quickly view breaker status, Gen-set status, and power levels. The VMM can also be used to start and stop Gen-sets. The start/stop functions are not available in this application.

The VMM allows the operator to monitor the respective Gen-sets. The VMM is also used to adjust system parameters or configurations like the Gen-set PT and CT ratios, protective relays trip levels, and other Gen-set operating parameters.

A manual or user's guide is not currently available for the VMM software.

Operation Modes

The Allen-Bradley (A-B) PLC located in cabinet 4A controls the system operation. The A-B PLC controls the three Gen-sets. Gen-sets 1 & 2 are diesel fueled, emergency Gen-sets. Gen-set 3 is a natural gas fueled cogeneration unit. The system operation (A-B PLC) was not altered during the March 1999 work and operates as it did prior to March 1999. Details regarding the operation can be found in the original switchgear documentation.

The following is a summary outlining the operation. Each Gen-set is equipped with a five position rotary switch (Engine generator control switch, SS2/__C) located on the door panel. The engine generator control switch has five modes of operation:

- Off / Reset
- Off / Cooldown
- Automatic
- Test Off-Line

- Test On-Line

Off / Reset

The Off / Reset has two functions. First, Off causes the Gen-set to stop immediately. The Gen-set will bypass the engine cooldown time and shutdown. Second, Reset causes the Gen-set alarm(s) to be reset. Inactive alarms will clear and active alarms will remain. The alarm(s) cannot be cleared until the conditions causing the alarm(s) have returned to the normal operating levels.

The Off / Reset should only be used to stop a Gen-set prematurely during dangerous or emergency situations. The Off / Reset can be used any time the Gen-set is stopped to reset an alarm(s).

When Off / Reset is selected, the Gen-set is locked out. The Gen-set will not be available and will not start if an utility outage is detected by an ATS.

Off / Cooldown

The Off / Cooldown has one function. Selecting Off / Cooldown will unload the Gen-set, open the generator breaker, and run the engine for the cooldown time period (5 minutes). After the cooldown period has expired the engine will shutdown.

The Off / Cooldown is the normal method used for stopping the Gen-set during a load test or during automatic operation if the unit is no longer needed.

Automatic

The Automatic mode has one function. Automatic is the normal operating condition for the Gen-set. In Automatic, the Gen-set is normally stopped waiting for a utility outage. If an ATS detects a utility outage, the Gen-set will receive a start command from the ATS and PLC. The Gen-set will start, accelerate to rated speed, synchronize or close to a dead generator bus. Once the generator breaker has closed, the ATS will transfer the load to the generator bus and the Gen-set will pick up the load. The Gen-set will remain online until the utility service has returned. Once the ATS determines the utility service is available, the ATS will transfer the load from the generator bus to the utility bus. The Gen-set breaker will open, the engine will cooldown for the cooldown time (5 Minutes) and shutdown after the timer has expired. The Gen-set will be ready for automatic operation if another utility outage is detected by an ATS.

Test Off-Line

The Test Off-Line will start the engine and run at rated speed as long as the engine generator switch is in Test Off-Line. The engine will shutdown if Automatic is selected. The cooldown timer will be bypassed in this case because the engine was not loaded. The generator breaker will not close while Test Off-Line is selected.

If an ATS detects a utility outage while Test Off-Line is selected, the Gen-set mode will switch to Automatic, close the generator breaker and pick up the load.

Test Off-Line can be used to perform engine maintenance, check for leaks, and so on.

Test On-line

The Test On-Line will start the Gen-set, accelerate to rated speed, and close the generator breaker to a dead bus. The Gen-set will run on-line as long as Test On-Line is selected. The Gen-set will remain on-line as long as Test Off-Line is selected. Automatic must be selected before the Gen-set will shutdown. The Gen-set will go through a cooldown cycle because the generator breaker was closed.

If an ATS detects a utility outage while Test On-Line is selected, the Gen-set mode will switch to Automatic and pick up the load.

Multiple units may be tested on-line at the same time. The system will load share at zero load indefinitely.

Cogeneration & Baseloading

In addition to the Gen-set modes described above, the A-B PLC allows the Gen-sets to be operated in Cogeneration (Gen-set 3 Only) or Baseload (Gen-set 1 & 2 Only) modes. The engine generator mode switch must be in Automatic for either mode to function. Cogeneration and Baseload allows the site to reduce its load requirements when requested by the utility company, Public Service of New Mexico (PNM).

Cogeneration or Baseload is selected using the data terminal located on panel 4A. The data terminal is connected to the A-B PLC and the A-B PLC controls the Gen-set load set point via the load sharing lines connected to the GPC's.

Cogeneration mode will only use Gen-set 3. Baseload mode will only use Gen-sets 1 and/or 2. If Gen-set 3 is in Cogeneration mode and Gen-set 3 trips off-line, Gen-sets 1 & 2 will start automatically and load up to the previous cogeneration load level. The system will not switch automatically from Baseload to Cogeneration if Gen-set 1 and/or 2 fails.

If an ATS detects a utility outage while the site is cogenerating or baseloading, the Gen-set mode will switch to Automatic and pick up the load.

Manual Operation

Manual operation is not currently available. ENCORP does not recommend running or attempting to run the Gen-sets manually in the switchgear's current condition.

> **NOTE**: The switchgear does not have the means necessary to manually control the Gen-sets. Since the original installation, the speed trim potentiometers have been

disconnected from the engine governors (Woodward 2301A LS&SC). Without the speed trim potentiometers, the engine speed cannot be easily trimmed, or adjusted. The PT and CT wiring has been modified to go to the ENCORP GPC AND the Woodward 2301A to allow the Woodward 2301A to be operated in droop, however this is extremely difficult without the proper training and experience.

Calibration & Maintenance

The following calibration and maintenance recommendations apply the ENCORP equipment and switchgear. The engine, generators, cooling systems, fuel systems, and other major components should be serviced and maintained using the manufacturer's recommendations.

Calibration

None of ENCORP hardware requires any periodic calibration once the initial installation is completed.

The protective relays (40 and 47 devices) should be calibrated annually or as required by the utility service provider (Public Service of New Mexico).

If a GPC or MMC is replaced with a new unit, the new unit must be calibrated. The following is a list of the I/O that must be calibrated and is specific to the hardware:

- A¬, B¬, C¬, & 1¬ Potential Transformer Inputs (PT's TB41-TB48)
- A¬, B¬, & C¬ Current Transformer Inputs (CT's TB33-TB38)
- Frequency Bias Output (TB52-TB54)
- Load Sharing Lines (TB65-TB76)

The procedure for calibrating the above I/O is in the ENCORP publication: *en*power Products, GPC/MMC/UPC, Installation and Configuration Guide (P/N: 05.001.00008. The remaining calibration, or configuration variables, will be loaded as part of the project download

> **WARNING**: If an *en*power device must be replaced, the replacement device must be installed properly in the switchgear AND the *en*power project. This includes the proper node replacement in the project, and binding set download. The *en*power device replacement procedure is outlined in Chapter 4.0 Troubleshooting.

Maintenance

None of the ENCORP hardware requires any periodic maintenance or service. The *en*power hardware is designed to provide years of trouble free service.

The enpower hardware (GPC's & MMC) and CPM are powered by separate uninterruptible power supplies (UPS) providing 120Vac. The UPS for the GPC's & MMC will provide over thirty minutes of operation in the event of a power outage. The UPS for the CPM will provide up to ten minutes of operation in the event of a power outage.

Both UPS's have an internal battery that requires periodic replacement. The battery should be replaced every three years. Consult the UPS user's guide for further details including battery part numbers.

The UPS's should be tested monthly. The UPS has a test button on the front of the unit. Refer the UPS user's guide for further instructions.

Twice a year, the UPS should be disconnected from the 120Vac utility source to verify the UPS is capable of carrying the GPC/MMC and CPM for a minimum of five minutes.

Troubleshooting

This section provides general troubleshooting guidelines for the switchgear.

It is assumed the operator has a working knowledge of electronics / electricity, electronic testing equipment, and personal computers (PC). An understanding of governors and voltage regulators is also helpful.

Refer the appropriate OEM manuals for troubleshooting the engine, generator, or other major components not part of the switchgear. The engine and generators have alarms based on several conditions including high water temperature, low oil pressure, etc.

The primary tools for troubleshooting the system will be the CPM and the annunciator panels located on the switchgear doors. Generally, the annunciator panels located on the panel doors will provide the operator with the current alarm or condition. For problems, most likely caused by the GPC, the VMM software on the CPM will provide the most information. The *en*power hardware (GPC & MMC) have light pipes installed in the cover to view the circuit board light emitting diodes (LED). The LED's provide the operator with a visual indication of the GPC's status. The CPM also allows ENCORP personnel to help troubleshoot the system remotely. ENCORP can dial into the site, monitor the system operation, and provide troubleshooting assistance.

The ENCORP publication: *en*power Products, GPC/MMC/UPC, Installation and Configuration Guide (P/N: 05.001.00008) is included with this operation manual. The guide includes I/O testing procedures for the *en*power hardware.

Technical Support

For technical support, contact ENCORP:

Phone: 888-362-6771
Fax: 970-686-9416
E-Mail: techsupport@ENCORP.com

Returning Equipment

When returning ENCORP equipment for service or repair, ENCORP must issue a Return Material Authorization (RMA) number prior to returning the equipment.

Field Service

ENCORP provides field service support for its products. The ENCORP field service rates in included in section 2. Contact ENCORP for further details.

Watchdog LED

The GPC watchdog LED is green and must be illuminated for the GPC or MMC to function properly. The *en*power hardware takes about 10 seconds to complete its self test and boot up after power is applied to the unit. The watchdog LED will be off during the start up.

If the LED is not illuminated one of the following has happened and the control will either need to be reset (Cycle power) or replaced:

- Failed power supply or no power applied
- Watchdog circuit has time out
- Failed GPC or MMC hardware
- Unit is booting up

LonWorks Network LED

The LonWorks LED is red and is illuminated whenever the *en*power device is broadcasting information on the LonWorks network. The GPC LonWorks LED will typically blink about once every second. The MMC does not have any bindings that require the network and will not be on most of the time.

Serial Port Communications LED

The serial port communications LED is red and is illuminated whenever the GPC is using the serial communications port. The serial port is only used to down load the ISaGRAF embedded PLC software so the LED will normally be off.

Replacing an enpower Device

If an *en*power device is determined to have failed and needs replacing, the following procedure must be followed. Refer to the *en*power Products, GPC/MMC/UPC, Installation and Configuration Guide (P/N: 05.001.00008) and the *en*telligent NST Binding Software 3.0 (P/N: 05.002.00004) manuals for further information.

WARNING: qualified service personnel should only attempt an enpower node replacement. The service personnel should be aware of Electro-Static Discharge (ESD) and exercise care handling the circuit boards.

1. Disconnect the AC (120Vac) and DC (24Vdc) power to the panel
2. Lock the Gen-set out by shutting off the fuel supply to the engine
3. Remove the *en*power device cover
4. Mark and/or label all wires going to the *en*power device
5. Remove all wires and disconnect all connectors from the *en*power device
6. Remove the *en*power device from the panel
7. Install the new *en*power device
8. Connect the wires and all of the connectors to the *en*power device
9. Connect the AC (120Vac) and DC (24Vdc) power to the panel
10. Record the neuron ID located on the new *en*power device digital board
11. Using the CPM, launch the ENCORP Network Service Tool (NST)
12. Open the latest NST project for the site
13. Select the old node from the NST node list and replace the node using the new neuron ID
14. Open the Lon Talk Adapter (PCNSS)
15. Find all of the nodes using the NST and verify all of the nodes are connected
16. Download the bindings to the LonWorks network
17. Select the new node and download the configurations to the new *en*power device
18. Save the configuration on the new *en*power device
19. Test the new *en*power device for proper operation and return the unit to service

Target:
Emerging Distributed Resource Technologies

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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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EPRI • 3412 Hillview Avenue, Palo Alto, California 94304 • PO Box 10412, Palo Alto, California 94303 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com