April 2003 • NREL/SR-560-33581

Subcontractor Report

Development, Demonstration, and Field Testing of Enterprise-Wide Distributed Generation Energy Management System

Phase 1 Report

RealEnergy
Woodland Hills, California

National Renewable Energy Laboratory

1617 Cole Boulevard
Golden, Colorado 80401-3393

NREL is a U.S. Department of Energy Laboratory
Operated by Midwest Research Institute • Battelle • Bechtel

Contract No. DE-AC36-99-GO10337

April 2003 • NREL/SR-560-33581

Development, Demonstration, and Field Testing of Enterprise-Wide Distributed Generation Energy Management System

Phase 1 Report

RealEnergy
Woodland Hills, California

NREL Technical Monitor: Holly Thomas

Prepared under Subcontract No. NAD-1-30605-11

National Renewable Energy Laboratory

1617 Cole Boulevard
Golden, Colorado 80401-3393

NREL is a U.S. Department of Energy Laboratory
Operated by Midwest Research Institute • Battelle • Bechtel

Contract No. DE-AC36-99-GO10337

Available electronically at http://www.osti.gov/bridge

Available for a processing fee to U.S. Department of Energy
and its contractors, in paper, from:
U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831-0062
phone: 865.576.8401
fax: 865.576.5728
email: reports@adonis.osti.gov

Available for sale to the public, in paper, from:
U.S. Department of Commerce
National Technical Information Service
5285 Port Royal Road
Springfield, VA 22161
phone: 800.553.6847
fax: 703.605.6900
email: orders@ntis.fedworld.gov
online ordering: http://www.ntis.gov/ordering.htm

Printed on paper containing at least 50% wastepaper, including 20% postconsumer waste

List of Acronyms

ATC	Authority to construct
C&C	Command and control
CAL ISO	California Independent System Operator
CEC	California Energy Commission
CHP	Combined heat and power
CPUC	California Public Utilities Commission
DG	Distributed generation
DEIS	Distributed Energy Information System
DER	Distributed energy resource(s)
DSL	Digital subscriber line
EMS	Energy management system
GUI	Graphical user interface
HX	Heat exchanger
IC	Internal combustion
ICE	Internal combustion engine
ICMMBAC	Integration, communications, metering, monitoring, billing, alarm, and control
I/O	Input and output
IOUs	Investor-owned utilities
ISDN	Integrated services digital network
LADWP	Los Angeles Department of Water and Power
LAN	Local area network
LHV	Low heating value
O&M	Operations and maintenance
PCC	Point of common coupling
PML	Power Measurement Limited
POTS	Plain old telephone service
PTO	Permit to operate
PURPA	Public Utility Regulatory Policy Act
PV	Photovoltaic(s)
QF	Qualifying facility
RE	RealEnergy
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
TOU	Tim of use
VFD	Variable frequency drive

0. Executive Summary

This report, submitted by RealEnergy (RE), is in fulfillment of deliverable D-1.4 of subcontract NAD-1-30605-11, the “Annual Technical Progress Report.” It is a description of RE’s evolving command and control system, called the “Distributed Energy Information System” (DEIS).

This report is divided into six tasks. The first five describe the DEIS; the sixth describes RE’s regulatory and contractual obligations.

- Task 1: Define Information and Communications Requirements
- Task 2: Develop Command and Control Algorithms for Optimal Dispatch
- Task 3: Develop Codes and Modules for Optimal Dispatch Algorithms
- Task 4: Test Codes Using Simulated Data
- Task 5: Install and Test Energy Management Software
- Task 6: Contractual and Regulatory Issues

Each task represents one chapter in this annual technical progress report.

0.1 Task 1: Define Information and Communications Requirements

0.1.1 Purpose

The purpose of this task is to define the information inputs and supporting communication requirements needed to model a virtual utility application. The identification of information and communication requirements is the first step in designing the command and control modules for optimal enterprise dispatch of distributed power.[1]

0.1.2 Overview

The challenge for RE’s growing fleet of more than 5 MW of distributed generation (DG) systems in California is *how to meter, monitor, operate, and dispatch all of the systems with off-the-shelf technology that is cost-effective and relatively simple.*

In determining its input and output (I/O) requirements for communications and control, RE determined that:

- It needed few data inputs
- Most necessary inputs were simple and unvarying (such as utility rate tariffs)
- A few inputs, such as engine heat rate and absorption chiller output, were complex and variable
- Data outputs were far more important than inputs
- Data outputs for optimal metering, monitoring, and operations were many and complex
- Large quantities of data were necessary for billing and operations.

[1] Distributed power includes systems that produce electricity and (for CHP systems) thermal energy at the end-user site, where the electricity and heat energy products are consumed.

RE decided to capture a rich output data set so it would have flexibility to use this information in the future in ways it does not yet foresee.

0.1.3 Dispatch Inputs and Metering Outputs

Dispatch protocols based on inputs were simple based on RE's operating criteria: (1) no export, (2) no load following, (3) fixed gas purchase tariffs, and (4) fixed electric sales tariffs.[2]

Generation inputs:

- Site demand
- Time of day
- Utility rate tariff

Thermal inputs:

- Supply temperatures: cogeneration, building, and cooling tower
- Return temperatures: cogeneration, building, and cooling tower

Each category of output below has many subcategories, as detailed in the Appendix.

Generation outputs:

- Voltage
- Current
- Power
- Frequency/Power factor
- Energy

0.1.4 Generation Output Categories

Metered outputs can vary by technology; however, in general, the categories remain the same with only minor specialization. The following table describes how each category is metered.

Table 0.1-1: Output Measurements

Categories Measured	Measurements Taken
Voltage	High, low, and average voltage output both in sum and across all three phases, plus unbalances
Current	High, low, and mean current across all three phases
Power	High, low, and mean ampere reactance
Frequency/Power factor	High, low, and mean on power factor lag and lead
Energy/Demand	Kilowatts received from the utility along with the quality of that power and its ampere reactance
Harmonics	Harmonic distortions on voltage and currents
Sag	Duration, magnitude, cause, and time of the sag
Waveforms	Cause, time, voltage, and current

[2] Inputs become more rich and complex in tasks 2 and 3 under optimal dispatch.

0.1.5 Thermal Input Categories

Thermal controls require four subcategories integrated with the building energy management system (EMS) for proper and safe dispatch.

- **Main Meter**
  Once engines start, the Main Meter requests building signal “OK to Run,” indicating building chilled water demand.

- **Field Hardware I/O Modules**
  Supply and return temperatures from the cogeneration, building supply, and cooling tower loops are assessed to control valve openings and ensure that waste heat is used safely and optimally.

- **Engine**
  Hot water jacket inlet and outlet temperatures are measured.

- **Absorption Chiller**
  Building return temperature is measured to act as a signal to increase, decrease, or hold RE’s supply of chilled water.

0.1.6 System Designed for RealEnergy Inputs and Outputs

For optimal operation, the DEIS was built around a minimum of two Power Measurement Ltd. (PML) ION 7500 meters:

- **Main Meter**
  monitors the utility main service and usually also serves as a gateway for sending data
- **Generator Meter**
  monitors and controls all the generator functions.

The Generator Meter connects to all the DEIS devices to control and monitor the system. The Main Meter monitors the utility main electrical service into the building. It also, in this case, serves as the gateway, the communication device for transmitting information to RE operations, IT, and billing personnel.

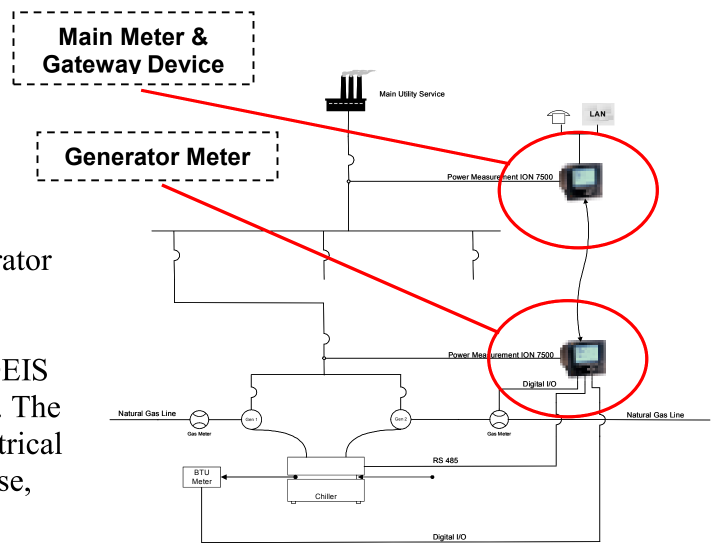


Figure 0.1-1: Two ION meters

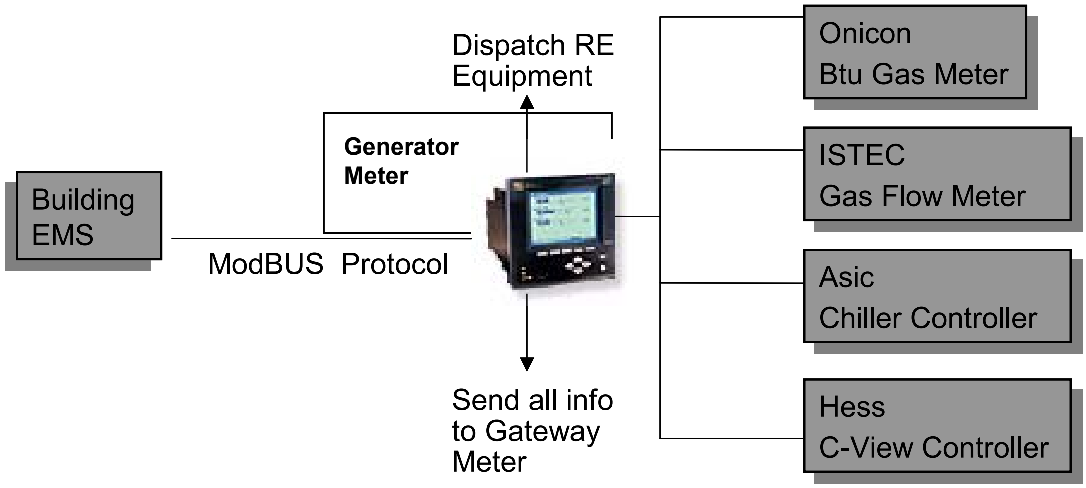


Figure 0.1-2: The Generator Meter integration with hardware/software devices

0.1.7 Hardware to Integrate Through Software

The Generator Meter must integrate with the proprietary data systems of other vendors' hardware/software devices. Integration is essential for quantifying British thermal units delivered to the customer, how much chilled water to bill for, and gas usage to gauge engine heat rates and fuel usage as well as for controlling the absorption chiller controls and the engine.

0.1.8 Alarms – Parameters

The DEIS is designed to send several types of alarms to operations personnel:

General

- Non-start
- Operating outside threshold (<160 kW or >240 kW)
- System event, such as engine start-up or shutdown
- High engine temperature
- High oil pressure
- Other excessive temperature.

The alarms are configured to be: (a) conditional on the run times of the engines, which are (currently) set according to the typical building operational schedules and the rates and tariffs, (b) capable of alarm delivery to staff for immediate notification in case of failure or another emergency, (c) stored in the DEIS database for later review for operational improvements, and (d) able to verify and validate message accuracy to ensure the alarms are valid.

0.1.9 Conclusions

- The RE metering system has been successfully operating and billing for more than 5 MW of DG systems in California since October 2001.
- There has been only one incident over millions of kilowatt-hours of operations that was not captured by the metering system.
- Refinements are forthcoming but are not mission-critical.

0.2 Task 2: Develop Command and Control Algorithms for Optimal Dispatch

0.2.1 Purpose

The purpose of this task is to develop the optimal command and control (C&C) algorithms for dispatching and managing power within a distributed energy network. To achieve this, RE isolated system metrics influencing optimal dispatch. It is also developing C&C algorithms that automate the choice of dispatch options. This task looks at a system located at a single site involving a photovoltaic (PV) array and internal combustion engines (ICEs) with heat recovery. The critical system components affecting economically optimal dispatch are:

Operating Revenues

- Electric rate tariff
- Total kilowatt-hours from ICE delivered @ tariff
- Total kilowatt-hours from PV delivered @ tariff

Value of generated electricity

- Btu price
- Total Btus delivered @ price

Value of heat capture[3]

Operating Costs[4]

- Cost of gas @ fixed/variable rate
- Cost of operations and maintenance for ICEs, PV, and heat recovery[5]
- Engine heat rate @ kilowatt output

Cost of generated electricity

- Cost to run existing electric chiller(s)
- Cost to produce existing hot water

Cost of thermal load

0.2.2 Existing System

- Electricity supply: electric utility distribution system
- Thermal "supply": electric chiller (pass), gas boiler(s)
- Average load: placard and 50 MW
- Peak load hours: 6 a.m. until 6 p.m.
- Non-peak hours: 6 p.m. until 6 a.m.

0.2.3 New System

- New electricity supply: Two 200-kW ICEs, 107-kW PV array
- New thermal supply: absorption chiller for chilled water; process or domestic hot water
- Back-up by existing electric and thermal supply systems

0.2.4 New System Interactions

- PV reduces peak load up to 100 kW, depending on cloud cover and time of year.
- Gas prices alone can make operations non-economical.
- ICE heat rates affect load-following capabilities.
- Fuel price per kilowatt-hour goes up geometrically with (relatively) linear heat rate increase.
- Throttle-Down Thresholds are limits to economic dispatch.

---

[3] May be a combination of absorption cooling and hot water heating.
[4] Costs do not include initial equipment purchase and installation cost because these are assumed to be sunk costs.
[5] Assumed to be $0.015 in this report.

0.2.5 Optimal Dispatch

Load shape is best fitted to:

- Run ICE-1 as base load 24/7
- Run PV as "peaking" source during daylight hours
- Run ICE-2 as a "marginal" unit.

Also:

- Running ICE-2 as a marginal unit requires load following
- There may be operational obstacles to real load following
- A 5% design margin above load is needed to cushion against export
- Can use 100% of thermal capture to cool the building, both from ICE-1 and ICE-2
- Thermal credit is especially valuable when electric chillers are at partial load.

To calculate optimal dispatch:

1. Record building load per period. Subtract 5% for design margin.
2. Calculate the cost per kilowatt-period to operate the engine at the kilowatt level from Step 1. [To calculate cost per kilowatt-period, follow steps 2-5 listed under Section 2.3.5.3; then divide the result ($/kWh) by 4.]
3. Calculate operations and maintenance (O&M) cost per kilowatt-period by dividing O&M cost ($0.015/kWh) by 4.
4. Calculate the total cost per kilowatt-period by adding the results of Step 2 and Step 3.
5. Calculate net earnings per period by multiplying the result of Step 4 by the period kilowatts.
6. Perform the above calculations for: no solar day (PV tripped), maximum solar day and minimum solar day.
7. Calculate the thermal credit by multiplying the ton-hours of cooling produced by the price per ton-hour.

0.2.6 Conclusions

- On non-holiday weekdays, the design for ICE-1, PV, and ICE-2 does not require dispatch decision, except for the percent to run ICE-2.
- ICE-2 percent will equal net building load less 5% design margin unless that number is less than the Throttle-Down Threshold, in which case ICE-2 should be shut off.
- On holidays and weekends, max solar days require a dispatch decision: whether to trip PV or ICE-1 (ICE-2 is off).
- The results for a marginal day requiring a PV/ICE trip decision are:
    - The no-solar day, solar-max, and solar-min days all show negative earnings prior to adding the thermal credit.
    - The thermal credit (value of absorption chiller) is $95 for the day.
    - The max-solar day earnings, including thermal credit, are $18.
    - The min-solar day earnings, including thermal credit, are $28.
    - The no-solar day earnings, including thermal credit, are $35.

    - The max-solar day earnings without ICE are \$70, but forego the thermal credit; replacement of the thermal credit would make those earnings negative (-\$25).
    - Optimal dispatch would result in the ICE being shut off from 7:30 a.m. until 4:30 p.m. (on the particular Sunday in question).
    - Optimal dispatch would result in earnings for the day of \$45.

- The optimal dispatch algorithm will shut off ICE-1 when the period earnings from the PV exceed the value for the period of the thermal credit.
- The optimal dispatch will be test-implemented to the extent practicable given real field conditions. Those limitations will be explored in Task 4.

0.3 Task 3: Develop Codes and Modules for Optimal Dispatch Algorithms

The purpose of this task is to develop optimized codes — for the algorithms developed in Task 2 — that enable the optimal dispatch of RE's fleet of systems.

0.3.1 The DEIS Revised Flow

A number of revisions are made to the logic of the algorithms from Task 2. The biggest change is the elimination of the Startup() function that formerly preceded main(). Start-up tasks are now handled the first time the program runs. Program flow is shown below.

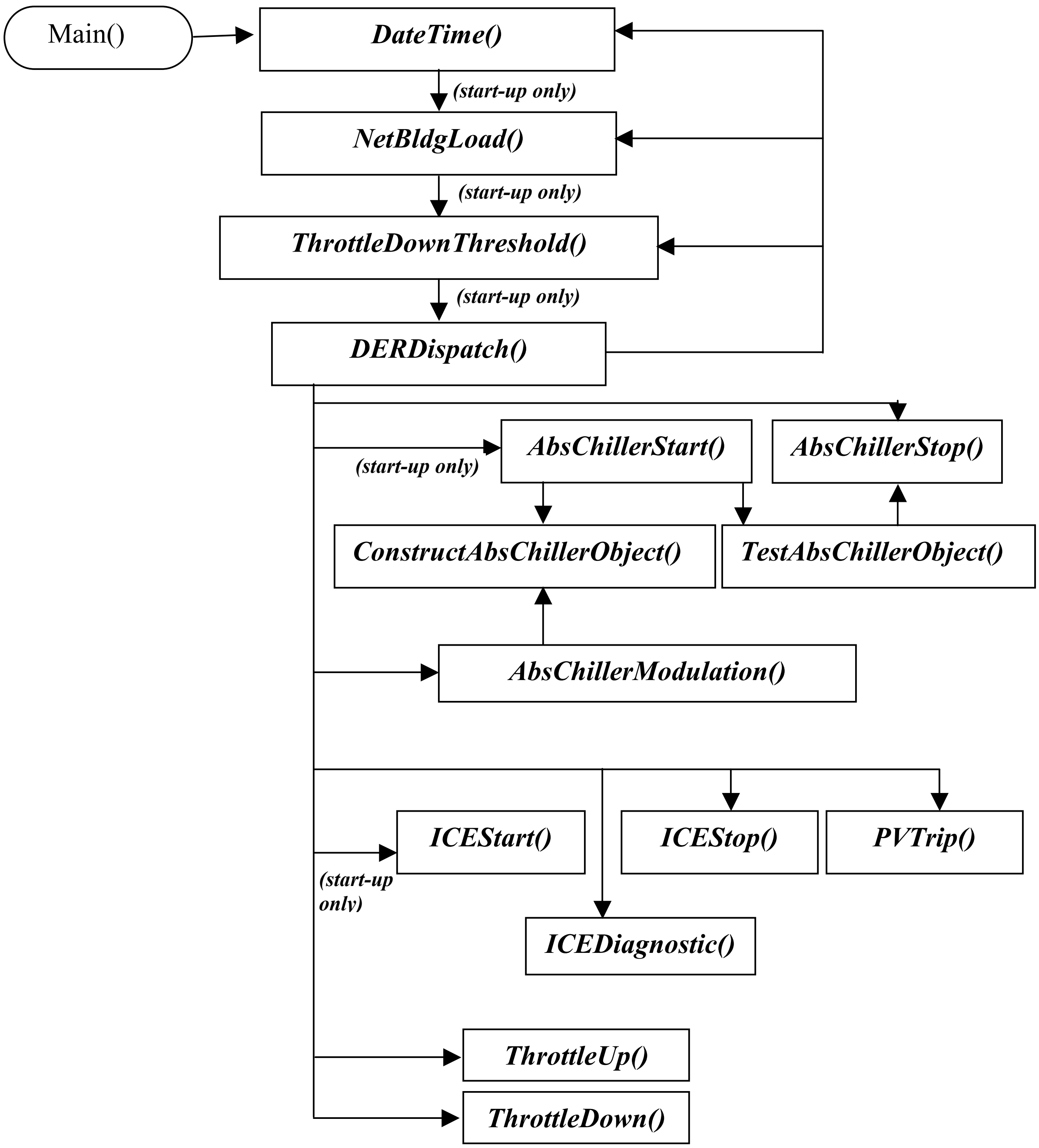


Figure 0.3-1: The DEIS flowchart, revised

0.3.2 Detailed Look at the Revised Program Flow
On program start-up, main() runs the following:

- DateTime()
- NetBldgLoad()
- ThrottleDownThreshold()
- DERDispatch().

When DERDispatch() first runs, it:

- Checks for the "OK to run" signal from the building
- Makes sure it is a valid time to operate.

If these conditions are true, the following actions are performed:

- DERDispatch() runs the AbsChillerStart()
- AbsChillerStart() runs ConstructAbsChillerObject(), which gets all temperatures and valve openings of the absorption chiller system
- AbsChillerStart() calls TestAbsChillerObject(), which runs diagnostics on the system
- DERDispatch() checks whether the current building load is big enough to run ICE-1
- If so, ICEStart() runs and starts up ICE-1
- If this happens successfully, DERDispatch() goes into continuous operation mode.

In continuous operation:

- DERDispatch() runs AbsChillerModulation()
- AbsChillerModulation() runs ConstructAbsChillerObject(),which gathers supply and return temperatures and valve settings from each of the three system absorption chiller loops: the cogeneration water loop, the condenser water loop, and the chilled water loop. This is accomplished in the function.
- Every 1 minute, DERDispatch():
    - Calls NetBldgLoad() to update load fluctuation
    - Gets PV output
    - Gets ICE electric and thermal output
    - Calculates the value of all these
    - Throttles up if load has risen
    - Throttles down if load has decreased
    - Starts ICE-2 if net building load can handle it
    - Stops ICE-2 if net building load cannot handle it
    - If operation is below the Throttle-Down Threshold, figures out if thermal credit plus loss is greater than PV output. If so, it trips PV; if not, it stops the marginal ICE.
- Every 60 minutes, DERDispatch():
    - Calls DateTime()
    - Calls ThrottleDownThreshold() to refresh these values.

Under normal conditions, DERDispatch() continuously calculates thermal credit and rate tariffs and operates ICEThrottle() to maximize system profitability.

0.4 Task 4: Test Codes Using Simulated Data

The purpose of this task is to test and improve the codes using data from field monitoring as a functional test platform to improve the algorithms and rewrite code and code design as necessary.

0.4.1 Non-Optimal Dispatch

In testing the design from tasks 2 and 3 in the testing platform — or, in other words, in assessing the actual field operations of the system — it is clear that dispatch is not optimal. There are a number of areas in which revenues are not captured and operations are made more costly and problematic, as the following table illustrates.

Table 0.4-1: RealEnergy Operational Issues

	Operations Not Yet Optimal				
Issue #	***Issue***	***Problem***	***Impact***	***Solution***	***Implementation***
1	Static On/Off Modified Dispatch	Time clock on/off control, modified by Device 37	Lost revenue	A more flexible controller	Cost
2	Time and Power Output Granularity: Throttle Controllers	Throttle control only allows on or off	Lost revenue	A more flexible controller	Cost
3	Data Integration: Proprietary Data Vocabularies	System components use proprietary data vocabularies	Lost revenue	Data translator; DG data standard	Cost
4	Engine Efficiency: Heat Rate Curve	Field heat rate of engine unknown	Lost revenue	Test the field heat rate	Cost
5	CHP Thermal Capture: Actual Data	Actual ton-hours less than rating	Lost revenue	Adjust thermal credit	None
6	Auxiliary Load Efficiency	No VFDs, fans run full on	Lost revenue	Install VFDs	Cost
7	Load Management: Inrush Current	Inrush current spikes at system start-up	Lost revenue	Use synchronous or improved controls	Cost

0.4.2 Issue 1: Modified On/Off Dispatch

RE's dispatch now is by time clock. The engines' start and end time is the same every day unless the load is insufficient at start-up or prior to shutdown. To prevent incidental export, the system automatically shuts off if the load dips below the 5% design margin above actual load. The interconnection agreement with the utility requires some insurance against export for a non-export agreement. This is static or "on\off" dispatch. Non-export provisions modify time-clock dispatch when the system shuts off to prevent export (sometimes called "Device 37" after its American National Standards Institute implementation).

Solution and progress:

- Get a more flexible controller.
- RE has tested and will continue to test controllers.

0.4.3 Issue 2: Lack of Output Granularity

The core issue here is that RE's controller cannot run the engine at partial load; it can only run at 100% or 0%. This causes two forms of lost revenue:

- Must size the kilowatt capacity more conservatively because of the inability to follow marginal load fluctuations
- Must lose all revenue outside the "square hole" in the load (see Figure 4.2.2-2) made by the engine running full out at 200 kW.

Solution and progress:

- Get a more flexible controller.
- RE has tested and will continue to test controllers.

0.4.4 Issue 3: Data Integration – Proprietary Data Vocabularies
Each of the following parts of the hardware/software substructure of the DEIS uses proprietary data vocabularies or protocols in a current RE installation:

- The building control EMS
- The absorption chiller controller
- The ICEs controller.

Solution and progress:

- The ad hoc solution applied thus far has been to purchase a hardware/software translator box for each component and custom program it to force integration according to set rules of the custom programming.
- A more long-range solution would be an industry standard data vocabulary that manufacturers support in their products.

0.4.5 Issue 4: Engine Efficiency – Heat Rate Curve
One of the most important numbers needed for optimal dispatch is the Throttle-Down Threshold, the lowest kilowatt threshold the engine can *profitably* maintain (within safe operating parameters). To calculate this number on the fly, it is desirable to know actual heat rate for that engine at that time. A second-best solution would be to develop an accurate heat rate curve for the engine in question through testing. However, RE has observed wide discrepancies in apparent heat rate from one installation to another. The fact is, dispatch may become optimal only to the extent that actual heat rates are known. Anything less will lead to inaccuracies, non-optimal dispatch, and lost revenue. Of course, as long as the engines are operated at 100%, a heat rate curve is unnecessary. We will see lost revenue from issues 1 and 2. Currently, there is no reliable data for 100% operation. It is possible that the company may believe it is operating profitably when, in fact, it is not.

Solution and progress:

- A heat rate study is being carried out now for some sites.
- The company is assessing the feasibility of calculating heat rate for each machine in real time.

0.4.6 Issue 5: Combined Heat and Power Thermal Capture – Actual Data

In review of the Btu meter data (the only data gathered at that point), it became obvious that the system was very rarely producing 100% of its rated capacity of British thermal units. In fact, it seemed to do so for only two periods (15-minute intervals) in 2 months. The rest of the time, the system operated at 40%–60% of its optimum. Now, it could be that the building was not calling for the cooling. But this is unlikely for two reasons:

1. Why would two periods experience 100% load and the rest experience loads a little more than half that?
2. The combined heat and power (CHP) system thermal cooling is supposed to be the first dispatch option for cooling for the whole building. It is very unlikely that the absorption chiller (without the electric chillers) at half capacity could cool the whole building. It is not impossible, but it is unlikely.

Btu meters are known to be prone to error, so perhaps the data is faulty. If so, RE needs to recalibrate or replace the meters.

Solution and progress:

- A solution is difficult, in part because this can be an area of conflict with the building owners if they actually use some other cooling as first dispatched.
- The Btu meters have not been calibrated or tested.
- No comprehensive approach to calculating exact revenue loss from faulty thermal capture is planned now.

0.4.7 Issue 6: Auxiliary Load Efficiency

Auxiliary loads are those pieces of equipment needed by the generating facility that require electricity to operate. Because they reduce the net output of the generator (to the extent that the electricity produced is used by them), they are also called "parasitic loads." Many of these loads, such as the "balance radiator" fans,[6] are only needed occasionally.

To ramp operation up and down according to need will usually save a lot of energy — up to 50% or more. But it requires additional monitoring and control by a variable frequency drive (VFD). Currently, there is no VFD control on any parasitic load. Because parasitic loads run 5%–10% of output electricity at various sites, it is possible that adequate control in this area could add 2.5%–7% to the project bottom line. This could be the difference between a winning and a losing installation.

Solutions and progress:

- RE is currently assessing the actual parasitic loads for each site.
- Savings available from VFDs and other controls are being studied.
- The costs of the solutions are being gathered.
- The paybacks involved in applying the solutions are being assessed.

[6] These fans cool cogeneration return water that has not run through the absorption chiller.

0.4.8 Issue 7: Load Management – Induction Inrush Current

When an induction generator starts up, it draws an enormous amount of current from the grid. Although this spike does not last long, it may have some deleterious effects. The worst imaginable consequence would be for the building owner to be assessed a demand charge for this spike. It is unknown whether this has ever happened.

Solutions and progress:

- There may be some controls available that could limit the induction spike.
- A bill analysis and operational analysis for all existing customers could determine whether the issue had ever caused a problem, either operationally or in demand charges. If there had been no problem, perhaps no further action would be necessary.
- So far, there has been no indication that such analysis has been or will be done.

0.4.9 Conclusions

- Economic analysis of economic impact of three types of dispatch should be completed. Based on this potential cost savings, RE should research and pursue cost-effective options for dynamic control — i.e., control that can run the generators based not on the clock but on actual operating conditions.
- At the same time that RE is assessing dynamic control, it should improve controller granularity. Now, in essence, there is no granularity because a time clock is set once based on the minimum "bucket-size," i.e., building load. We have shown that this approach leads to lost revenue, incidental export, or both. Once the controller can be changed automatically, dynamically, it will be desirable to be able to make very fine adjustments from 0 kW to 220 kW.
- Interoperability is the one issue that RE has addressed so that it does not stand as an operational or economic barrier to project profitability. However, even though RE has solved the problem for its existing sites, it is desirable for RE and the industry to have communications standards and open systems that will allow maximum interoperability at least cost in the future.
- It will be unwise to use the whole generator range without having a very accurate heat rate curve. Without it, dispatch control will not know what the lower limit is of profitability (i.e., the Throttle-Down Threshold) for any given facility on any given day. RE needs to have excellent heat rate data. When that information is gathered, Throttle-Down Thresholds may be calculated dynamically at whatever time interval is appropriate.
- The thermal data show a very interesting situation: that the field unit can produce 97% of manufacturer-stated thermal output (at least), but it only produced this output twice in almost 3 months. It is possible that, because the data were for winter, the cooling load was handled almost entirely by the economizers and only required half-output from the absorption chiller. That flies in the face of cooling load data from the building, however. (See, for example, Figure 2.2.1-2, which shows that cooling loads vary less than 20% between the hottest and coolest months.) The average thermal capture is only 59%. Something may be wrong with the way the system is being operated. The absorption chiller should serve as chiller base load for the building, but it is not currently being dispatched that way. This requires further follow-up, analysis, and solution.

- No RE auxiliary loads have VFDs on them at present, so it is certain that they are wasting electricity. Paybacks will vary by site, but VFDs are likely a cost-effective solution. Quantitative analysis remains to be done.
- Inrush current analysis should be easy and should tell quickly whether the customers are being billed in any instances for kilowatts drawn by induction motors at start-up. Solutions include possible control devices to reduce inrush spikes or use of synchronous generators.

0.5 Task 5: Install and Test Energy Management Software

0.5.1 Introduction

When RE entered the energy arena in June 2000, the business was based on compilation and analysis of energy usage patterns in commercial properties. Driven by software with great promise, RE took a bold step forward to implement this unproven technology. RE began to assemble its core staff to fulfill its corporate mission. The pace was furious, the challenges were formidable, and the promises for global change were compelling. RE formulated two sets of criteria for its information system:

Technical Criteria

- Platform device capabilities
  - a. Precision
  - b. Quantity and diversity of outputs
  - c. Compatibility with building EMSs
  - d. Availability of device drivers
  - e. Software/hardware integration and interoperability
  - f. Enterprise-wide solution capability; Internet deliverability
- Compatibility with proposed installation environments
  - a. Ability to operate at extremes of temperature and humidity
  - b. Device durability
  - c. Remote operation
  - d. Low maintenance
- Industry accepted *non-proprietary* communications protocols to encourage vendor participation in future development

Business Criteria

- Data ownership
  - a. RE must be able to transmit data from its own projects.
  - b. RE must be able to own data from its own projects.
  - c. RE must be able to archive data from its own projects.
- Initial Cost

  Device first cost must meet RE's internal cost criteria.

- ♦ Recurring Cost Structure Model
    a. After purchase, the device should have no lingering service costs.
    b. The device should have no recurring costs.

- ♦ After sale engineering
  To serve its evolving site-specific and enterprise-wide needs:
    a. RE required excellent after-sale support for installation
    b. RE required support for customization.

- ♦ Flexibility
    a. RE is a technology-agnostic organization, which specifies and installs the best technology for the application.
    b. RE's future designs incorporate hybrid or multiple technology installations. The control platform must be versatile enough to support any and all configurations.

0.5.2 Vendor Assessments

Silicon Energy

Silicon Energy is an enterprise energy management software company. RE planned initially to rely heavily on it for building energy data management. Problems arose in attempting to get the Silicon Energy software to work with existing building control software and monitoring hardware. Still, 180 points were installed in seven buildings. RE tried to find hardware to work with the Silicon Energy suite but ultimately was unsuccessful in the attempt.

Silicon Energy met these RE technical and business requirements:

- Capable of modeling any quantity and diversity of outputs
- Enterprise-wide solution capability
- Highly advanced graphical user interface (GUI)
- Internet deliverability
- Data ownership.

Silicon Energy did not meet these RE technical and business requirements:

- Remote system control capability
- Billing solution
- Compatibility with proposed installation environments
- Compatibility with many building EMSs
- Software/hardware integration and interoperability
- Complete solution
- Remote operation
- Low maintenance
- Low first cost
- No lingering service costs or recurring costs
- Timely and affordable after-sale engineering.

eLutions

eLutions, part of the Invensys/Engage company network, came to the table with what appeared to be an exciting package. It offered a Web-based front end and had developed SCADA hardware used by many OEM manufacturers. RE believed its package might be able to bridge the gap between the software and building hardware/controls.

eLutions met these RE technical and business requirements:

- Capable of modeling any quantity and diversity of outputs
- Compatibility with proposed installation environments
- Advanced GUI offering interactive charting to create “what if” scenarios
- Compatibility with building EMSs
- Software/hardware integration and interoperability
- Enterprise-wide solution capability
- Internet deliverability
- Low maintenance.

eLutions did not meet these RE technical and business requirements:

- Precise billing solution
- Data ownership
- Integrity of information developed
- Remote system control capability
- Device durability
- Capable of precision
- Low first cost
- Long term, multi-site contract structure
- No lingering service costs or recurring costs
- Timely and affordable after-sale engineering.

Enflex

Enflex manufactures hardware to fill the hardware gap that customers of enterprise energy software makers, such as Silicon Energy, were facing. There was no supporting software, leaving it reliant on enterprise software products such as SiE’s for its success.

Enflex met these RE technical and business requirements:

- Compatibility with proposed installation environments
- Data ownership
- Low maintenance
- Remote operation
- No lingering service costs or recurring costs
- Ability to operate at extremes of temperature and humidity.

Enflex did not meet these RE technical and business requirements:

- Control and billing criteria
- Compatibility with a diverse set of building EMSs
- Internet deliverability
- Software/hardware integration and interoperability
- Capable of precision
- Low first cost
- Timely and affordable after-sale engineering
- Capable of modeling any quantity and diversity of outputs
- Enterprise-wide solution capability.

Envenergy

Envenergy is a young California-based company that makes a hardware-only system for building energy and load management. It requires enterprise energy management software (such as Silicon Energy's) to work. At the time of RE's testing of the device, there was only one unit available. It was a prototype; no Envenergy production product existed.

Envenergy met these RE technical and business requirements:

- Compatibility with proposed installation environments
- Low maintenance
- Remote operation
- Ability to operate at extremes of temperature and humidity
- Device durability.

Envenergy did not meet these RE technical and business requirements:

- Control and billing criteria
- Compatibility with building energy management systems
- Internet deliverability
- Software/hardware integration and interoperability
- Capable of precision
- Low first cost
- Capable of modeling any quantity and diversity of outputs
- Enterprise-wide solution capability
- Commercial availability
- Data ownership
- No lingering service costs or recurring costs.

Power Measurement Limited

Power Measurement Ltd. (PML), unlike many of the other platforms tested, had established products in the field. PML is a large company with excellent after-sale support. The platform consists of integrated hardware and software. At this time, PML meets all of RE's needs, though this will be re-evaluated in the future.

PML met these RE technical and business requirements:

- Compatibility with proposed installation environments
- Clear understanding of precision power measurement
- Billing-ready data and conversion software
- Ability to adapt to constantly evolving requirements
- Multiple simultaneous communications ports
- Industry standard Modbus RTU communications protocol
- Low maintenance
- Remote operation
- Ability to operate at extremes of temperature and humidity
- Device durability
- Compatibility with building EMSs
- Internet deliverability
- Software/hardware integration and interoperability
- Unlimited scalability
- Capable of modeling any quantity and diversity of outputs
- Enterprise-wide solution capability
- Commercial availability
- Data ownership
- No lingering service costs or recurring costs.

PML did not meet these RE technical and business requirements:

- None.

0.5.3 Conclusion

After a program of extensive research and field testing of software and hardware platforms capable of enterprise management of a fleet of distributed energy resources (DER), RE chose the ION system by PML. The PML ION system met all of RE's technical and business criteria. The ION is an inexpensive yet precise device available for purchase and installation off the shelf. When RE has needed custom programming to meet its specific needs, PML has been there to provide it.

0.6 Task 6: Contractual and Regulatory Issues

0.6.1 Current RealEnergy Projects

The following matrix shows RE's current projects.

Each project goes through the following stages:

- Project Stage 1: Contractual negotiations
- Project Stage 2: Prepare and begin construction
- Project Stage 3: Construction completion.

Table 0.6-1: RealEnergy's Current Projects
As of 3-31-2002

Project Name	Type	Size (kW)	Utility Territory	Tariff Rate	Status	IC Type
Carlsbad	Solar	110	SDG&E	A	Operating	"Net Metered"
Fountain Valley 17390	Solar	110	SCE	TOU8	Operating	Non-Export
Fountain Valley 17330	Solar	110	SCE	GS2	Operating	Non-Export
IBT	IC	600	SDG&E	ALTOU	Operating	Non-Export
Centerside 1	IC	400	SDG&E	ALTOU	Operating	Non-Export
Sky Park	IC	400	SDG&E	ALTOU	Commissioning	Non-Export
Genesse	IC	400	SDG&E	ALTOU	Commissioning	Non-Export
Oceangate	IC	400	SCE	TOU-8	Operating	Non-Export
Two Town Center	IC	1000	SCE	TOU-8	Commissioning	Non-Export
Boatyard	Micro-turbine	60	SCE	GS2	Operating	Non-Export
West Century	IC	400	LAWPD	S3	Operating	Non-Export
World Savings	IC	200	LAWPD	A3A	Operating	Non-Export
Lankershim	IC	400	LAWPD	S3	On Hold	Non-Export

0.6.2 Project Stage 1: Contractual Negotiations

Because of the long-term nature of RE's business model, the nature of the installations, and the types of clients RE works with, sizeable time and expenses must be expended in addressing "up front" issues.

Each of RE's contract negotiations took at least 3 months to complete. For one of RE's more complicated projects, it took more than 195 days to finalize the contract with the client. On average, RE's contract negotiations took approximately 116 days.

0.6.3 Project Stage 2: Prepare and Begin Construction

During Stage 2, RE must complete each of the following:

- Authority to construct permit (regulatory – regional)
- Building permit (regulatory – municipal)
- Design, site prep, and construction issues (regulatory and business – municipal)
- Interconnection application (regulatory – regional)
- Interconnection agreement (business).

0.6.4 Project Stage 3: Construction Completion

- Building shutdown (business)
- Building and safety sign-off (regulatory – municipal)
- Final interconnection inspection (regulatory – regional)
- Permit to operate (regulatory – regional)

0.6.5 Conclusion

The following conclusions may be drawn from RE's experience to date with contractual and regulatory issues:

- Educating local regulators and permitting authorities is still an issue and a cost for many projects.
- Many utility personnel lack training to properly review the impact of DG on the grid.
- Some field personnel may have a bias against DG left over from the days of the Public Utility Regulatory Policy Act (PURPA).
- Utilities themselves are not aligned with allowing DG to be installed because it decreases utility distribution system revenue, which is based on kilowatts flowing through the lines. To this extent, investor-owned and many municipal utilities in California are not agnostic about DG and have been cooperative only in select instances. A mechanism decoupling rates from kilowatt-hour distribution — such as the Electric Rate Adjustment Mechanism of the days of demand-side management projects — might help, though it is likely to be opposed by the investor-owned utilities because it is a ratepayer subsidy for DG.

The question remains how long utilities can resist DG as the technologies come within economic reach of an ever-increasing portion of the ratebase.

Table of Contents

Table of Figures

Table of Tables

Task 1: Define Information and Communications Requirements

1.1 Introduction
The purpose of this task is to define the information inputs and supporting communication requirements needed to model a virtual utility application. The identification of information and communication requirements was the first step in designing the command and control modules for optimal enterprise dispatch of RealEnergy Inc. (RE) combined heat and power (CHP) and photovoltaic (PV) systems.

1.1.1 Overview
To date, RE has installed distributed energy systems at 13 sites in California. That number is growing rapidly. These sites provide unique and valuable insights into the universe of issues distributed energy developers face:

- How various technologies perform
- How they affect and how they are affected by the distribution system
- How they affect and are affected by the building and building loads they serve
- What technical, physical, legal, regulatory, and market barriers exist to distributed energy
- How to operate a fleet of enterprise-wide distributed energy resource (DER) assets across various utility service territories and geographical regions.

However, without accurate information to assess various performance metrics, the vital operating information coming from these machines and needed to both profitably operate RE's fleet of systems and shape the on-site power market is lost. To address this, RE's sites are linked to RE's distributed energy information system (DEIS). The DEIS provides RE with the information necessary to manage and optimize its operations, bill for its services, and serve the needs of its clients.

To RE's knowledge, the DEIS is unique in the industry. The information the system gathers, while proprietary, is of general interest to the global distributed energy community. The hardware and software supporting the DEIS is commercially available and is, in itself, not uncommon. The value of the system is in the integration of software with existing hardware to create a system that is as unique as the information it collects. This task defines the information and communication requirements of the DEIS.

- Sections 1.1.2 and 1.1.3 will provide an overview of the information and communications requirements.
- Section 1.2 will discuss how the interface works.
- Section 1.3 will discuss requirements for integration, communications, metering, monitoring, billing, alarm, and control.
- Section 1.4 will discuss inputs and outputs and how these affect dispatch.
- Section 1.5 will discuss gateway, hardware, and software requirements.
- Section 1.6 will discuss requirements for information extraction from the database.
- Section 1.7 will discuss conclusions and next steps.

1.1.2 Information Requirements

RE's information and communication requirements are driven by billing and operational information needs within its installations. These are usually single commercial buildings, employing one or more distributed energy technologies that operate in parallel with the power grid. In effect, RE has created and operates a virtual utility network. The DEIS must, of course, gather information and control operations for all sites from a central location.

The requirements for one site, however, do not affect requirements for the next. The sites operate in isolation from one another, providing the benefits of a diverse portfolio and also achieving economies of scale for items such as gas commodity procurement. RE's portfolio currently consists of sites that use PV arrays, microturbines, and internal combustion (IC) gas engines with heat recovery capability. Although these technologies are not currently operating together at any one site, RE plans to outfit one or more future sites with both PV and internal combustions engines (ICEs) with heat recovery to run an absorption chiller and (optionally) building hot water supply. Because the DEIS requirements for this configuration are the most complex in the portfolio RE plans to operate, these requirements will be the subject of this report.

RE has found through experience that it needs only a few select information inputs for dispatch control but a much larger and more diverse set of outputs for its billing procedures and operations. RE makes no decision about whether to run based on market prices because there is no direct access market. It does not export because of the cost and complexities of Federal Energy Regulatory Commission Wholesale Distribution Access Tariffs. It does not play ancillary services markets because the California Independent System Operator (Cal ISO) has not been able to pay its providers because of nonpayment by its scheduling coordinators. (They are not paying because high wholesale prices have driven them into or close to bankruptcy.) This makes the DEIS system inputs much simpler: no fluctuating prices, no export. The two prime variables at individual sites, along with their applicable tariff schedule, are the matching of generation to the building load during the off-peak periods and the matching of thermal energy output to the building demand during shoulder heating and cooling periods.

Fluctuations in weather, operations and maintenance (O&M), user risks, and gas prices can affect the profitability of a project on a daily basis, but usually they do not have a great enough variability to affect the decision of whether to dispatch a technology on a given day. Take a hypothetical installation in California consisting of a microturbine, PV array, and ICE for cogeneration — all operating on economic dispatch to serve a commercial building on a time-of-use (TOU) tariff. The dispatch order would vary little: the PV would be dispatched on all weekdays and most weekends; the engine and the microturbine would compete for dispatch based on thermal efficiency.[7] Whichever was more efficient would always be dispatched when the building load (net of PV) exceeded its nameplate output kilowatts, plus some margin. The unit would then operate at 100% output. If the load reduced, the generation could theoretically follow the load down to a point at which it was no longer profitable to run (based on heat rate) or until its cost to run was higher than the other fossil-fired technology. At that point, the other technology could be dispatched if its operation, according to the electric tariff, was still profitable.

[7] This configuration, minus the microturbine, is the subject of Task 2, in which the actual dispatch situations are examined in much greater detail.

Maintenance should be scheduled for off-peak periods when system demands are lowest. TOUs and other operational constraints can also limit operation. As a general rule, RE found that sizing a system to approximately 50% of the building peak allowed optimal operation. This sizing avoids demand charges and accounts for maintenance and operational constraints. Gas prices and retail electric rates also affect dispatch decisions.

The model system described in this final report will include two ICEs with heat recovery and a PV system located in a commercial building. At the time of writing, RE does not have such a system in operation, though it plans to do so in the near future. The information used as the basis of this report is drawn from separate PV and ICE installations that exist in RE’s portfolio today. Dispatch and other operational details for this PV/ICE system are still theoretical; it is likely that RE's actual future operation of the system will vary from the model discussed here. This is part of RE's contribution to the advancement of the state of the art in distributed energy.

1.1.3 Communication Requirements

Communications hardware and software, including metering, is the foundation of the DEIS, providing the capability of data acquisition and control in real-time. RE preferred that its communications technologies be purchased and usable off the shelf as a system. None were available as a system, so RE built a system with off-the-shelf technologies and custom modifications and configurations. This included the gateway communications with various control signals. The system has three functional requirements: (1) communicate and operate the RE system on site, (2) interface with and manage the integration of the RE system with the host facility, and (3) communicate with the corporate office servers and mobile operations and maintenance staff. Communications and gateway hardware must be weather-resistant, extremely stable, durable, and easy to maintain. The communications infrastructure must be inexpensive, redundant in case of failure, and at least 64 kbps (128 kbps is preferable) for real-time control and diagnostic communications. RE requires that it maintain ownership and control of its site data and that it operate the system itself. The system must attain simplicity, integrating many functions into a single technology, while being easy and inexpensive to maintain.

RE made rigorous tests of many meters and software packages. Almost none met RE’s requirements. Aside from weather resiliency and “total” platform stability, RE required that each metering system be able to collect data from more than 80 metering points at 15-minute intervals, 24 hours a day, 7 days a week. Some systems had a first cost that was too high; other systems required the purchase of ongoing metering and monitoring service, which RE preferred to do in-house. Some companies insisted that RE's data be collected at their third-party location, remote from RE and its operations; some systems were PC-based, requiring frequent maintenance and lacking the capability to operate outdoors on rooftops and exposed to UV, rain, wind, and extreme fluctuations of temperature.

RE's requirements and tests led it finally to deploy the ION meters by Power Measurement Ltd. (PML). The first installations (including PV and microturbines) used the PML ION 7350; subsequent installations use the 7500 model because of its more robust data acquisition capabilities. After extensive field tests throughout the summer of 2001, RE found that PML’s ION line of products was the only truly capable of meeting RE’s needs. These meters can serve as a gateway device with the installation of a local area network (LAN) card. They are programmable. They are inexpensive (relatively) and can be owned and operated by RE. They are also weather-resistant and can operate down to -10°F.

The communications system begins with a modem-to-modem connection at 56 kbps over plain old telephone service (POTS). In the future, greater bandwidth will be added using static digital subscriber line (DSL) technology at 128 kbps upload and download or 64 kbps integrated services digital network (ISDN) lines if DSL is not available. RE will retain POTS availability at all times, as a dedicated standby, in case the broadband service goes down.

1.2 How the Information Interface Works

The DEIS is built around a minimum of two meters capable of:

1. Serving as a gateway to the RE servers
2. Providing all necessary functions, including integration, communication, metering, monitoring, billing, alarm, and control (ICMMBAC).

The PML ION integrates all these capabilities into a single unit. One of the two meters captures generating information (the Generator Meter); the other captures information about the main utility bus (Main Meter). Technically, either could serve as a gateway device as long as it has a LAN card installed. RE has chosen to implement the gateway through the main bus meter in most cases. This eliminates the need for a separate gateway device. The system measures gas flow to each ICE to allow the Generator Meter to provide heat rate calculations based on gas input and power output. The Generator Meter (sections 1.4.1–1.4.3) measures all of the other relevant aspects of engine operation. The system measures chiller operations using a Btu meter that captures thermal energy flow. Temperature data from the Btu meter goes to the Main Meter and from the Generator Meter to the building control system to serve the building chilled water load and to reject excess heat from the generators (see Section 1.4.1, Item 1.4). The RE billing and operations servers will have data mirroring capability to ensure no loss of data and flexibility of operations. The following physical and logical charts show the organization of the DEIS and other system components.

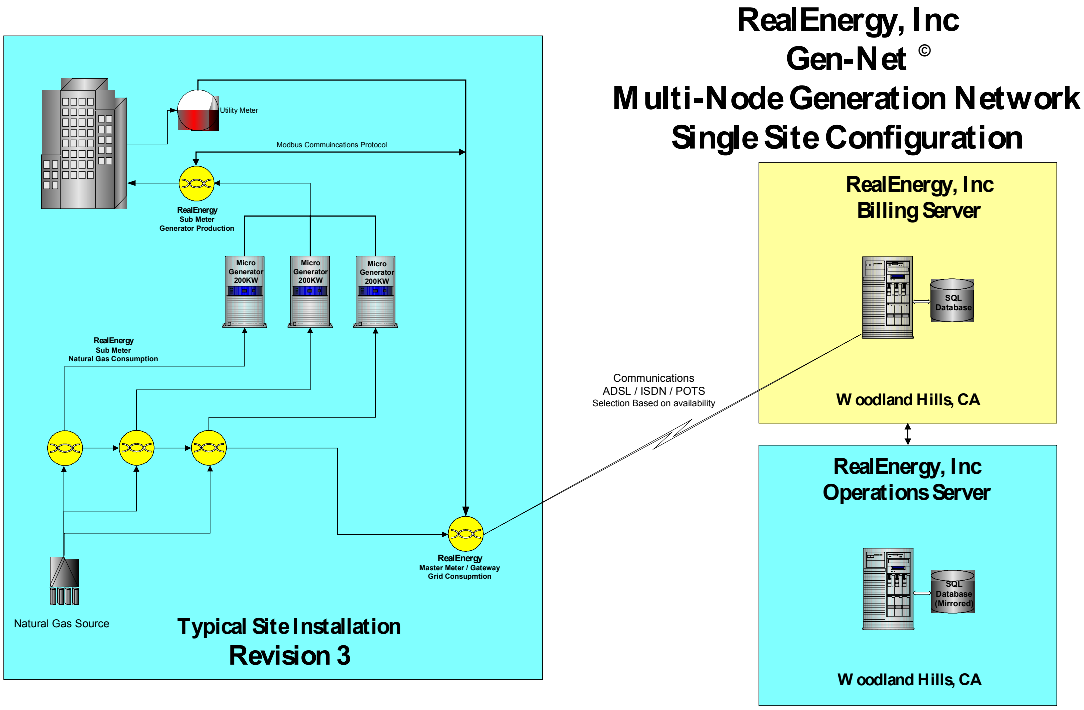


Figure 1.2-1: Physical site connection to RE billing and operations

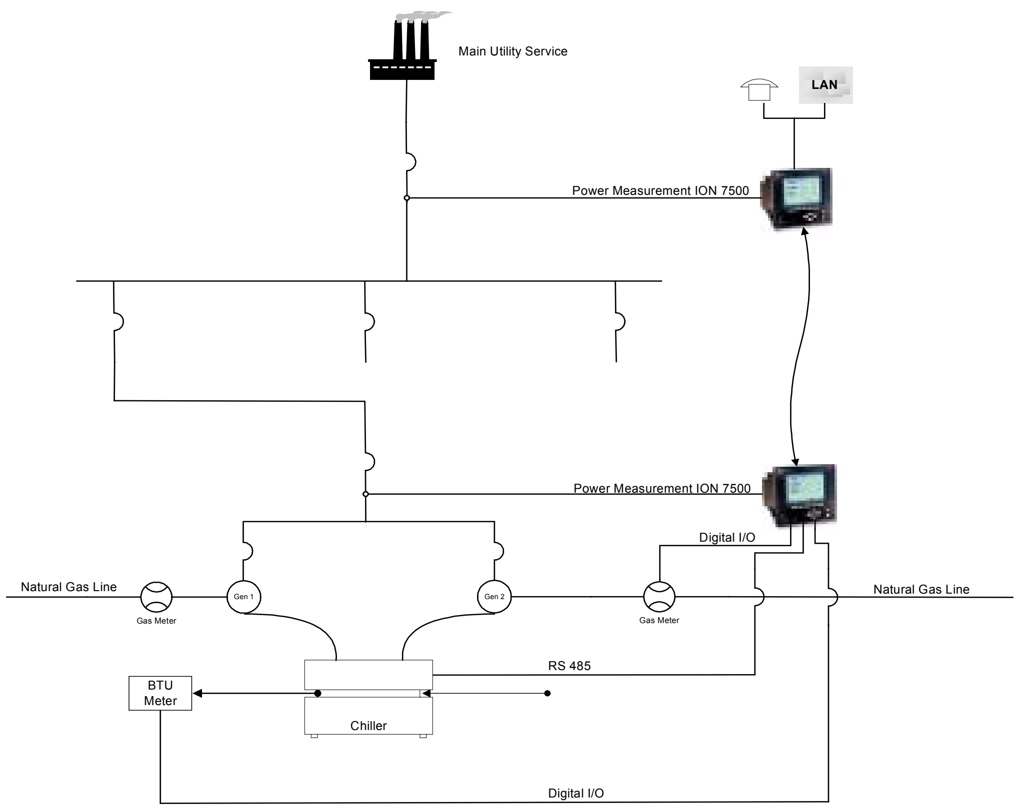


Figure 1.2-2: Logical site layout showing Main and Generator meters

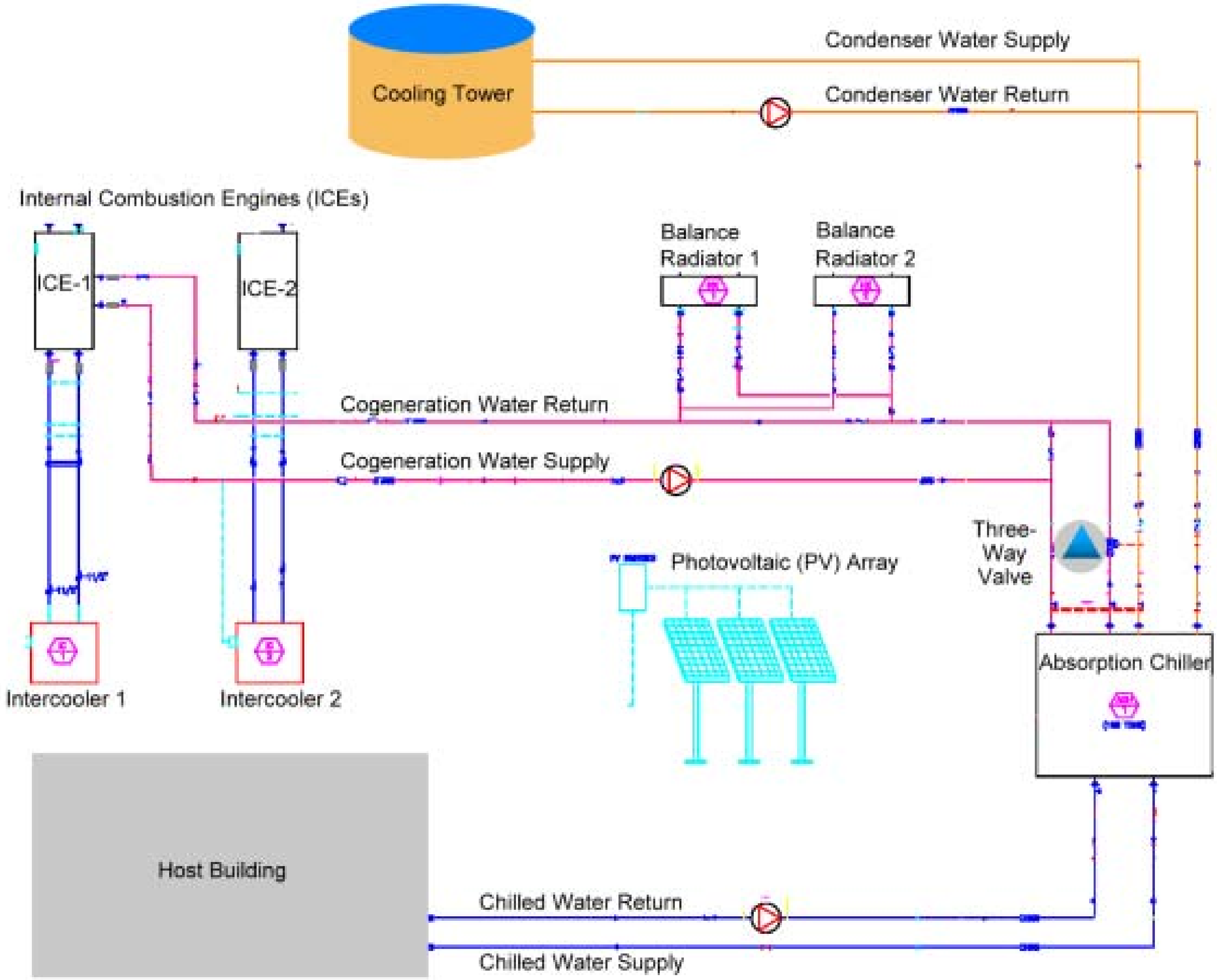


Figure 1.2-3: The DEIS schematic: PV, ICE, and thermal capture

1.3 The Distributed Energy Information System Requirements

Requirements for the DEIS are made up of seven components, each of which is made up of separate categories or process steps: integration, communications, metering, monitoring, billing, alarm, and controls. The DEIS is designed to fulfill as many of these requirements with as few devices as possible.

1.3.1 Integration Requirements

The requirements of system integration fall into nine categories:

1. System design
   The system design must take into account all aspects of the project, including the distributed energy technologies, the quantity and size of each technology, the building space into which the technologies will be installed, any unusual building layout issues, communications issues, metering quantities and placement, and controls issues.

2. Contractor selection
   Knowledgeable, experienced, and reasonably priced contractors must be selected.

3. Design review
   The contractors, RE, and the host customer must review the design to ensure feasibility.

4. Work authorization
   When the design is deemed adequate, work authorizations are sent to the contractors.

5. Communication planning
   POTS connections and broadband access are established with the site.

6. Communication integration
   All communicating devices are networked, either by hardwiring or via RS-485 data interface.

7. Project management and scheduling
   The activities of all contractors must be managed by RE to ensure desired results.

8. Validation
   Outputs from all devices must be tested for validity of data they are passing on. Inputs must be tested with real output data; controls must be tested for correct operation.

9. Payment authorization
   Payment of contractors must be authorized.

1.3.2 Communications Requirements

Communications requirements are as follows:

1. Planning
   Based on the size of the site and its location, RE must plan the type of broadband service it expects.

2. Line provisioning
   The lines necessary are requested from and provided by the local telephone service provider and other broadband provider.

3. IP address issuance
   One or more Internet protocol addresses are issued.

4. IP subnetting device configuration
   Devices operating under a single IP address are configured on the subnet.

5. Data transmission test
   The operation of the communications system must be tested.

1.3.3 Metering Requirements

Metering requirements are as follows:

1. Device selection
   Metering devices must be selected that are capable of fulfilling RE's device requirements. After significant hardware device testing, RE has selected premium metering devices that integrate all ICMMBAC requirements. Total integration simplifies the DEIS system design and reduces the possibility of component failure. There must be at least two meters: one for the utility main and one for metering the generators, as discussed above. There may be as many as four additional meters, depending on the size and complexity of the installation. These meters must have sufficient analog and digital inputs and outputs to cover all ICMMBAC requirements and to tie all the DEIS devices together. They must be capable of sending and receiving information from all other devices and providing control in real time upon receipt of critical input. The metering devices are the source of all data for the DEIS functioning, including system control, billing for delivered electricity, and operational outputs. The data must be accurate, timely, and secure.

   Beyond these two to six core meters, the DEIS requires a number of peripheral metering devices, including at least one Btu meter and at least one gas meter. The Btu meter must be capable of accurately measuring flow of absorption chiller return and supply and be able to calculate internally tons and ton-hours of refrigeration delivered for billing purposes. The water flow system temperature must be taken accurately at many points to allow proper operation of the heat recovery system. The DEIS requires gas flow meters to each engine to allow the determination of heat rate and overall system energy efficiency. Both the Btu meter and the gas meter(s) tie in to the Generator Meter, as shown in Figure 1.2.2-1. A list of all the metered data can be found in the Appendix under Meter Outputs.

2. Device configuration
   The Main and Generator meters must be configured with an appropriate memory capacity, communication protocol, and output information requirements. RE uses MODBUS communication protocol for energy management systems (EMSs). The device that will serve as the gateway must be configured with a LAN card.

3. Output calibration
   Output must be able to be calibrated for each device.

4. Output validation
   Output must be able to be validated for each device.

1.3.4 Monitoring Requirements

Requirements for reactive monitoring are as follows:

1. Validation prior to start
   Monitoring must be validated 15 minutes prior to system start to validate communications. Validation is accomplished by an Internet "ping."[8]

2. Validation after start
   Monitoring must be validated 15 minutes after start to verify normal operations.

3. Midday validation
   At midday, verify that operations are within tolerance, i.e., verify that generators are operating as they should be.

1.3.5 Billing Requirements

Billing requirements are as follows:

1. Database design
   Although the database has many operational functions and houses all output data at the RE offices, billing has the highest priority. The database must be designed to allow easy access to data used in billing calculation and report generation.

2. Database creation, management, backup, and validation
   The database design must be implemented and managed. Each additional site requires the creation of additional fields because of the variability of building EMSs. The data in the database must be backed up at least twice per day or more if downloads occur more often. Once it is created, the database must be tested to make sure it operates properly.

3. Database report design, report design review, report acceptance
   Reports to be output by the database for billing purposes must be designed to meet RE's

[8] "Ping" is a small program that requires an Internet IP address (or domain name) as a command-line argument. If the IP address is found and is connected to the Internet, the program returns a message saying that the site was found.

needs and the needs of the customer. A process must be designed to resolve discrepancies that arise from billing data.

1.3.6 Alarm Requirements

Reactive alarming requirements are as follows:

1. Site configuration
   Alarm set points must be designed and agreed on with the site customer. Alarms include:

   a. Non-start alarm (if generator is <5 kW output after 15 minutes)
   b. Outside operating threshold (if generator is <160 kW or >240 kW during operation)
   c. System event (if generator is not running for an unknown reason)
   d. High engine temperature (if generator is operating at greater than threshold temperature)
   e. High oil pressure (if generator oil pressure is greater than threshold pressure)
   f. Other excessive temperature (if generator is overheating).

2. Run-time scheduling
   The alarms must be made conditional depending on the time of day.

3. Integration
   The alarming system must be capable of alarm delivery to select individuals through the corporate e-mail system.

4. Server configuration
   The database server must be configured to handle alarms.

5. Message validation
   The alarm system must allow verification or validation that the message delivered is indeed accurate.

1.3.7 Control Requirements

Control requirements are divided into three areas: (1) general control requirements, (2) electric load control requirements, and (3) thermal load control requirements. These are as follows:

1. General control requirements
   The core meters and the controller must be part of the same system. Design simplicity requires integrating as many components as possible of the ICMMBAC. The DEIS Main Meter serves as the system control.

2. Electric load control requirements
   The control system must be able to receive a signal from the building EMS that the host is ready for the ICE generator(s) to be turned on. The controller must then power up the generator(s) and check for any system alarms. In California, a non-exporting generator must run at least 5% below total building load. The system must be capable of calculating

net building load after subtracting PV input from total building load; it must then subtract an additional 5% from the building load as a margin. The system must send the resulting number to a governor control device that can adjust the primary engine speed to match the input number.

Note that this load-following capability must operate within other limits in addition to the 5% rule. First, load control is only applied to the last engine, i.e., the bottom 200 kW. Second, load control must operate within the heat rate efficiency curve for the engine. Below some point in operation percentage of total power output, which we call the "Throttle-Down Threshold" in this report, engine operation would be very inefficient because of high heat rate. Throttle-Down Thresholds will need to be calculated on the fly. For now, RE runs engines at 100% or 0%. The generator protection package must be able to signal when the generator must power down and otherwise be acceptable under California's Rule 21. The main generator controller must be capable of receiving and carrying out a power down signal.

3. Thermal load control requirements
   The control system must be able to receive signals from the host facility control system about chilled water demand, and it must be able to regulate the operation of the absorption chiller to supply the required need. For RE's current systems, at start-up the system must start the system loop circulating pump, start the intercooler chiller operation, start the dump heat exchanger (HX) pump, and begin the process of warming the thermal system to operating temperature. Then the engine throttle will be opened to full power. The system must enable the HX pump and monitor its feedback status. After signaling the host building control system to enable the cooling tower fan set point control, the controller must give the signal to dump the waste heat from the operating generator into the building cooling tower.

   When chilled water is requested by the host, the system must enable the chiller to run by starting the condenser water pump, starting the chilled water pump, and slowly modulating the primary hot water control valve to begin the absorption process. The chiller controller must also operate the condenser bypass control valve to maintain a minimum entering condenser water temperature. The system must continually balance itself, sense flow of water through the condenser and the chiller, and then permit jacket water heated by the generators to flow through the jacket water supply line. When the host does not need the chilled water, the system must reduce the amount of jacket water flowing into it and increase the amount of jacket water that goes to the dump heat exchangers.

1.4 Definition of Communication Input/Output and Protocols for Optimal Dispatch

The following dispatch sequence is a model of system operation, not a description of an actual working system.

1.4.1 Electric and Thermal Dispatch

The system dispatch protocol modeled here is a single commercial building with PV, two ICEs with heat recovery, and an absorption chiller that ties into the existing building chiller through the existing building control system. (See Figure 1.2-3 for a detailed schematic of this system.) The protocol for dispatch is as follows:

1.1 Input: Signal OK to start generator (from host building control)
1.2 Process: If current clock time is within scheduled time of use (constant range), continue; otherwise, wait
1.3 Input: Overall building load (from Main Meter)
1.4 Input: PV output (from Generator Meter #1)
1.5 Process: Subtract PV output kilowatts from overall building load kilowatts; store result as net building load kilowatts (internal calculation)
1.6 Process: If net building load >105% of lead generator nameplate kilowatts, return OK; otherwise, wait
1.7 Control output: Enable building condenser water pump and cooling tower fan control
1.8 Input: If building says OK to run engine, then continue; else alarm
1.9 Input: Check for alarm
1.10 Input: Meter delivered kilowatt-hours
1.11 Control output: Start jacket water pump
1.12 Input: If jacket water pump amps >1.0, then continue; else alarm
1.13 Control Output: Start lead generator
1.14 Input: If lead engine is running, then continue; else alarm
1.15 Input: Check overall building load (from Main Meter)
1.16 Input: PV output (from Generator Meter #1);
1.17 Process: Subtract PV output kilowatts from overall building load kilowatts; store result as net building load kilowatts (internal calculation)
1.18 Process: If net building load >105% of total two generator nameplate kilowatts capacity, return OK; otherwise, wait
1.19 Control output: Start lag generator
1.20 Input: If lag engine is running and output is >20 kW, then continue; else alarm
1.21 Input: Check building chilled water demand
1.22 Process: If jacket water >165°F, then continue; else wait
1.23 Control output: Start chiller, condenser pump, and chilled water pump
1.24 Input: If condenser water pump amps >1.0 and chilled water pump amps >1.0 and chiller is enabled, then continue; else alarm
1.25 Input: If chiller capacity control valve is open >10%, then continue; else alarm
1.26 Control output: Modulate tower water bypass valve to hold supply water at 75°F
1.27 Input: Meter delivered chiller capacity to user.

1.4.2 Operational and Market Value of Information Gathered by the DEIS

The output of the DEIS is critical to RE internal operations. First, information is required for the operation of the systems on site. Second, the information is critical to the billing function, RE's revenue source. Third, it is critical to informing future RE operations. Operational decisions dependent on the DEIS include emergency maintenance; short-, mid-, and long-term maintenance; feedback for system optimization; revenue analysis; ancillary grid benefit analysis; grid interaction analysis; technology assessment; product warranties; product procurement; product development; and manufacturer relations.

The DEIS gives RE a complete success metric, whereby it can gauge the effectiveness of each technology in the field and each aspect of the service it provides the host customer. RE does not rely on manufacturer metrics and diagnostics but takes its own independent metrics to test manufacturer results and performance.

The output of the DEIS can inform the distributed energy market. The market participants that can benefit from the information the DEIS provides include existing customers; new customers; manufacturers; distributors; county planning, land use, and building departments; air regulators; utility commissions; state and federal energy offices; energy stakeholder groups; legislators; municipal utilities; distributed energy project developers; and investor-owned utilities (IOUs).

1.4.3 The DEIS Output Categories

There are eight categories from the Main and Generator meters for measuring electrical output: voltage, current, power, frequency/power factor, energy/demand, harmonics, sag/swell, and waveforms. Within each, there are subcategories, noted in the Appendix.

Outputs for the model building for this project (PV, single ICE with CHP, and a chiller) are determined partly by generation technology and partly by function. For clarity, the outputs reported here are for: (1) the Main Meter utility bus (typically, the gateway meter), (2) the Generator Meter for PV, (3) and the Generator Meter for the ICE.

There are four categories of thermal outputs: Generator Meter, field I/O hardware modules, engine(s), and absorption chiller(s).

1.5 Definition of Gateway, Hardware, and Software Requirements

1.5.1 Gateway

There is, as mentioned above, an overriding requirement of robustness for the gateway device. Because of its potential exposure to the elements, it must be temperature- and weather-resistant. RE, as discussed previously, eliminates an independent gateway device through the use of a multi-function meter with a LAN card installed for external communications. This gateway is typically the meter on the utility main bus. Although no failure has occurred so far, the gateway function of the DEIS can be made more robust by making the generator meter a back-up gateway.

1.5.2 Hardware

After considering many technologies from various manufacturers, RE has selected the following components for the DEIS:

- Main Meter, Generator Meter, and ICMMBAC: Power Measurement 7500 for all future installations of on-site generation. (The Power Measurement 7350 was initially used by RE, as mentioned above. RE later made a decision, based on its improved robustness and data-handling capabilities, to use the Power Measurement 7500.)
- Btu meter: Onicon Btu meter
- Gas flow meter: ISTEC gas flow meter
- Chiller controller: Asic

1.5.3 Software
The choice of software followed the hardware choice. RE uses Power Measurement's software Vista 3.0. RE has custom configured Vista to handle tariff schedules and multiple sites.

For the actual control of the generation equipment, RE is forced to use the proprietary C-VIEW software that comes pre-installed with the current model Hess generators. This non-integratable software is the only way to control the Hess units. In essence, RE must use these two software packages in parallel. The command and control system, anchored by the PML system, warns RE of any operational issues. The C-VIEW is then employed as the means by which RE can dial into each individual machine to remotely operate it.

1.5.4 Network Redundancy
The DEIS employs data mirroring to decrease the risk of data loss and system downtime. The RE Woodland Hills headquarters is entirely mirrored by the system in the RE Sacramento office. In addition to reducing risk, this approach increases flexibility.

1.6 Requirements for Database Information Extraction
The requirements for the database include:

- The database must have the ability to display the same information to two or more people at once.
- The database should be capable of handling the volume of data equivalent to all of RE's installations times the number of fields of data times the 96 updates per day times bytes per update.

RE selected Microsoft Sequel, the least expensive database with these capabilities.

Once the gateway and Generator Meters are installed, the outputs are mapped to the standard output design described in Section 1.4. Each output became a field in one of the tables for voltage, current, power, frequency/power factor, energy/demand, harmonics, sag/swell, and waveforms. Both Main and Generator meters have these same eight tables. But the data that populate the fields within the tables are unique, of course, because one set describes the utility bus and one describes the generators.

The fields vary slightly between outputs for the PML model 7350 and 7500. (See Section 1.4 for a detailed listing of outputs.) The RE database was set up by PML when the first meters were installed. The database is programmed using simple templates available in Microsoft Sequel 7.0, which runs in the Microsoft Windows environment.

The outputs used as inputs for billing are:

1. From the Generator Meter: Energy/Demand: kilowatt-hours delivered
2. From the Generator Meter: Power: kilowatt total high
3. Time of use (Generator Meter timestamp)
4. Region of California (different rates apply to different regions)
5. Tons of cooling delivered.

All outputs are potentially of use to RE operations.

1.7 Conclusion and Next Steps

Actual project installations and operations inform RE that, at this time, outputs are far more important than inputs to viable economic operation. The inputs needed for economic dispatch are few and simple while outputs are many and complex. The inputs and much of the design of the first system prototype have been found to be unnecessary under the current regulatory paradigm in California.

The data obtained thus far from RE’s nascent communication, command, and control system has shown that technologies with lower heat rates and economical installation costs will always be dispatched first or take precedence when part of a hybrid system.

For example, although PV has a high cost per installed kilowatt, once installed, it is relatively inexpensive to operate when compared with lower-cost generation technologies with much higher operation costs for fuel and maintenance. RE is now gathering data on maintenance of commercial PV. Output and operations data have shown these costs to be higher than expected. Unexpected problems of puddling, mold, and leakage on flat industrial roofs — while not necessarily degrading PV system performance — have raised long-term O&M issues. ICEs, too, have some operational shortcomings, such as noise, vibration (especially when mounted on a rooftop), and the sudden and very physical jolting of the surrounding structure when the unit synchronizes with the grid.

The controls supplied by the generator manufacturers have limited the load-following capabilities of the DEIS. RE is assessing various ways of bypassing these built-in functions to allow more flexible control of the generators. For now, the DEIS fulfills the requirements for simple and effective economic dispatch. It also gathers a wealth of data that is useful to RE, to the industry, and, possibly, to the future of energy.

Task 2: Develop Command and Control Algorithms for Optimal Dispatch

2.1 Introduction

The purpose of this task is to develop the optimal command and control algorithms for dispatching and managing power within a distributed energy network. To achieve this, RE isolated system metrics influencing optimal dispatch. This task discusses optimal command and control for power dispatch and management using RE's DEIS and its associated generation technologies to supply the electric and thermal loads of a commercial office space.

Optimal dispatch is defined as operating a specified set of energy production devices[9] in a manner that meets the needs of energy end-users at least cost. The way generation is dispatched will be affected by O&M considerations, too, but these are a part of the cost considerations of dispatch. O&M costs will be included, along with fuel costs, in this analysis.

2.1.1 Actual Versus Modeled Data

The example project will address the integration and management of distributed power technologies operating together in a network, including a PV array and a CHP system driven by natural gas-fired reciprocating ICEs. The engines supply electricity to the building through an induction generator; the PV supplies electricity through an inverter. The waste heat from the engines is captured and used by the building with an absorption chiller, which displaces a portion of the building space cooling load.

RE's portfolio today contains PV, engines with thermal recovery, and microturbines in separate installations. The system described here is a composite of several actual systems operating in the field today. During 2002, RE installed and operated ICEs, thermal heat recovery, and PV within a single building. This case of multiple distributed generators presented some distributed network dispatch design challenges. The approach taken will be to use data from existing separate systems and to combine them to form a more complex composite picture. Whenever possible, numbers used are recorded from actual field operations of the DEIS. Where information is not available, the numbers are modeled. Of course, the models might contain errors that lead to incorrect conclusions. Conclusions will be re-evaluated after comparison to actual operation.

2.2 System Overview

The existing building and its thermal and electric demand, supply, and tariffs will be described in sections 2.2.1 and 2.2.2; then the DEIS system supply will be overlaid in sections 2.2.3, 2.2.4, and 2.2.5. These data are from an actual, operating commercial building.

[9] The devices could also be energy consumption devices that are more efficient or are operated in a more cost-effective manner. This definition of optimal dispatch could be the criterion for assessing the value of all DERs. In this report, however, we will be considering only a small subset of energy generators.

2.2.1 Existing Electricity Supply and Demand

2.2.1.1 Building Supply

The building is supplied with electricity by the local distribution system, operated by Southern California Edison (SCE or electric utility). The building receives gas service from SoCalGas.

2.2.1.2 Building Demand

The building is a high-rise commercial space with 15 floors of commercial offices, a restaurant, and a health club. During the 1 year of baseline data, the peak was 674 kW. This occurred once in August and once in September. In both cases, the spike appeared at around 8 a.m. for one period[10] only. The kilowatt total for the 15 minutes before and after the spike was more than 100 kW lower. This suggests that the large chiller was started before the small one had been shut off. (See Section 2.2.2.2 on Existing Cooling Load).

The primary electric energy uses in the building are two chillers and their associated pumps and fans (approximately 45%), lighting (approximately 41%), and plug and other miscellaneous loads (approximately 14%). All tenants of the building, except the health club, maintain typical business hours (6 a.m. to 6 p.m. Monday through Friday). Some of the tenants work half-days on Saturday. The health club is open 24 hours, and it requires lighting and cooling and hot water at all times. This gives the

Utility Restructuring Under AB1890

Prior to electricity restructuring legislation passed in 1996 called AB 1890, utilities owned their own electric generation assets. But under AB 1890, utilities were asked by the California Public Utilities Commission (CPUC) to sell most of those assets on the open market. Independent operating companies purchased the assets and, under AB 1890, began selling the power to the utilities on a wholesale market. The utilities then sold the power to customers on a fixed-price retail basis. When the wholesale prices rose above the retail rates for a prolonged period in 2000 and 2001 (coinciding with high gas prices depicted in Figure 2.3.4-1), the state stepped in to purchase the power to save the utilities from bankruptcy.

Currently, the building is supplied with power purchased from the generators by a state agency, dispatched over the transmission system by the California Independent System Operator (CAL ISO), and delivered over the distribution system by the utility, which serves as the schedule coordinator to CAL ISO for customers in the utility's territory.

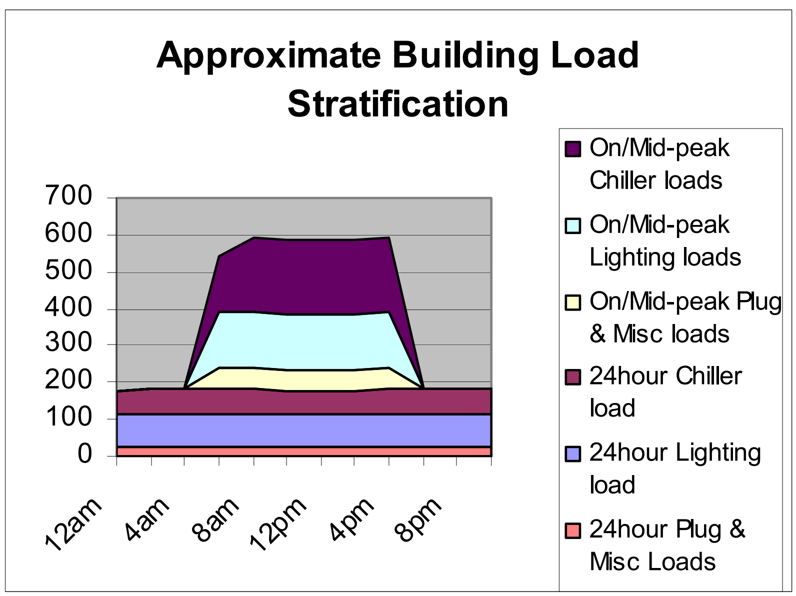


Figure 2.2.1-1 Approximate load stratification

[10] A period is a 15-minute interval; there are 96 periods per day. Most of the analysis in this report uses data by period.

building an average off-peak consumption of 224 kW and a minimum off-peak usage of 147 kW. The lowest peak capacity for any month on- or mid-peak occurs in March at 547 kW. The highest kilowatt total, 674 kW, occurs in both August and September. The difference between the summer peak and the winter peak is less than 20%.

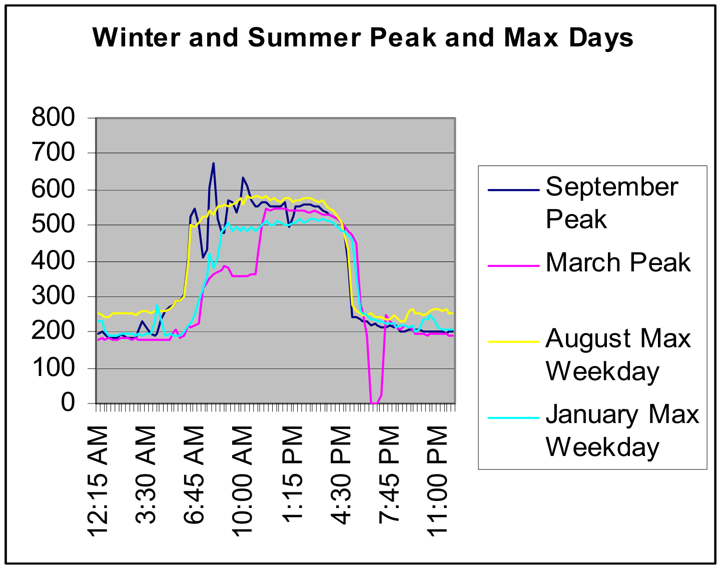


Figure 2.2.1-2 Winter and summer peak/max loads

The lack of seasonal variation in the electric load is partly due to the mild California coastal weather and the year-round tenant usage in commercial office space. The variation between the maximum daily kilowatt peak (674) and the minimum daily kilowatt peak (352) on a weekday represents a load difference of 48%. This load difference is attributable to the building cooling load.

2.2.2 Existing Thermal Supply and Demand

2.2.2.1 Economizers

The building is equipped with economizers, outside air intake vents. It is possible on many days of the year to cool the building in the morning and evening hours without using the chillers at all. The economizer fan motors are controlled with a variable frequency drive (VFD), so they can increase the air intake as the building warms in the morning. When the outdoor air temperature rises above the building cooling set point, the building EMS shuts off the economizer fans, closes the economizer louvers, and asks the electric chiller to turn on. The EMS will also shut off the economizer if the outdoor air humidity is above its threshold. Humid air is much more difficult to cool, so the energy savings of using the economizers is lost later when it is necessary to use extra chiller capacity to cool humid air. Also, humidity can encourage the growth of mold, an indoor air quality hazard.

2.2.2.2 Existing Cooling Load

The building has two chillers: one older 300-ton chiller and a newer 80-ton chiller. Both are centrifugal air-cooled chillers. The 300-ton chiller produces cooling at 1.13 kW/ton at 100% load; the newer chiller uses only 0.626 kW/ton. The smaller chiller was purchased because, although the 300-ton chiller had never failed to produce enough cooling for the building, it was inefficient when it ran at partial load, which happened more than 90% of the hours of the year.

Table 2.2.2-1: The 300-Ton Chiller Calculated Operating Efficiencies

Tons	% of Full Load	kW/ton	kW Consumed
300	100%	1.13	338.04
225	75%	1.17	264.06
150	50%	1.31	195.75
75	25%	1.75	131.09
45	15%	2.19	98.66
24	8%	2.77	66.48

Table 2.2.2-2 The 80-Ton Chiller Calculated Operating Efficiencies

Tons	% of Full Load	kW/ton	kW Consumed
80	100%	0.75	60.10
60	75%	0.78	46.94
40	50%	0.87	34.80
20	25%	1.17	23.30
12	15%	1.46	17.54
6.4	8%	1.85	11.82

The inefficiency was improved by running economizers as long as possible, drawing in cool and dry morning and nighttime air, and using the chiller during the middle of the day when the building reaches peak occupancy and the outdoor air is above the building set point. When a 24-hour health club became a tenant, it became necessary to supply cooling during the nighttime as well, from 30 to 80 tons. It is not possible to operate the economizers at night because the high moisture content of night air would invite mold formation. To handle this new load, the chiller was required to operate from 10% to 25% of capacity during all off-peak hours, at an efficiency of approximately 1.75 kW–2.5 kW per ton. This was unacceptable to building engineering staff. The building owners decided to purchase a more efficient, 80-ton chiller to expand the overall building cooling capacity and to serve the health club around the clock. The smaller chiller serves the same off-peak load with about 40% of the energy of the larger chiller.

In 2001, the building used a total of 466,560 ton-hours for all months and all tariff periods. A stratification of thermal load by month and tariff period shows that the building does not have a serious issue with peaking and, in fact, operates fairly constantly throughout the year.

2.2.2.3 Existing Chiller Dispatch

Because of the difference in efficiencies, it is less expensive to run the 80-ton chiller at all times at full load than to cover partial loads with the large (300-ton) chiller. For example, for 70 kW of power, the large and small chiller together can produce 83.6 tons of cooling at an average on-peak cost of $0.15 per ton — 80 tons for the small chiller and 3.6 tons for the large chiller. For 70 kW, the large chiller alone can only produce 32 tons of cooling at an average on-peak cost of $0.51 per ton. The average costs per ton tend to come toward the middle at higher loads. At 200 kW, both systems together produce 160 tons (roughly 80 tons each) of cooling at $0.23/ton. For 200 kW, the large system alone produces 153 tons of cooling at a cost of $0.24/ton. Therefore, existing chiller dispatch is simple: run the 80-ton chiller at all times at 100%; if load drops under 80 tons, use the small chiller as the marginal chiller.

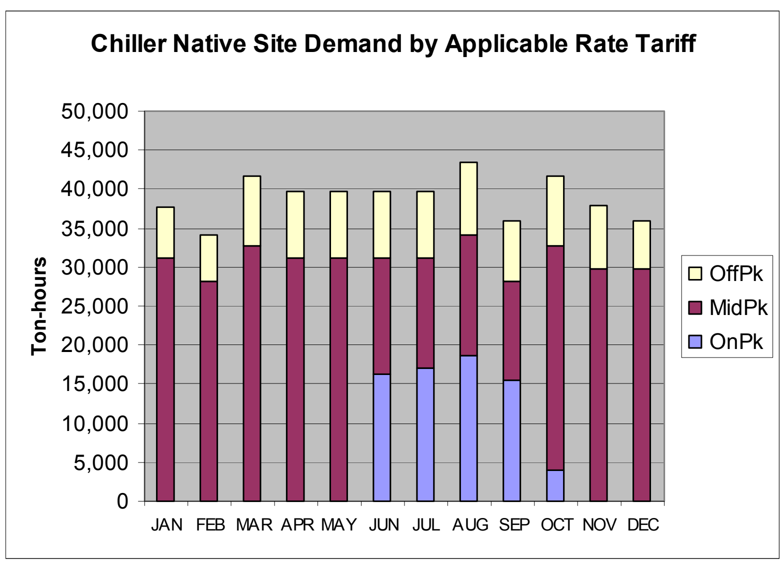


Figure 2.2.2-1: Chiller native site demand

The problem, clearly, with the above arrangement is that the large chiller is often running at less than 25% capacity and often at more than 2 kW/ton. When the building needs 85 tons of cooling, economic dispatch dictates that the small chiller should provide 80 tons and the large chiller should provide 5 tons at an efficiency approaching 3 kW per ton. This is not a desirable way to operate, yet it was the least expensive alternative the building had prior to the CHP installation.

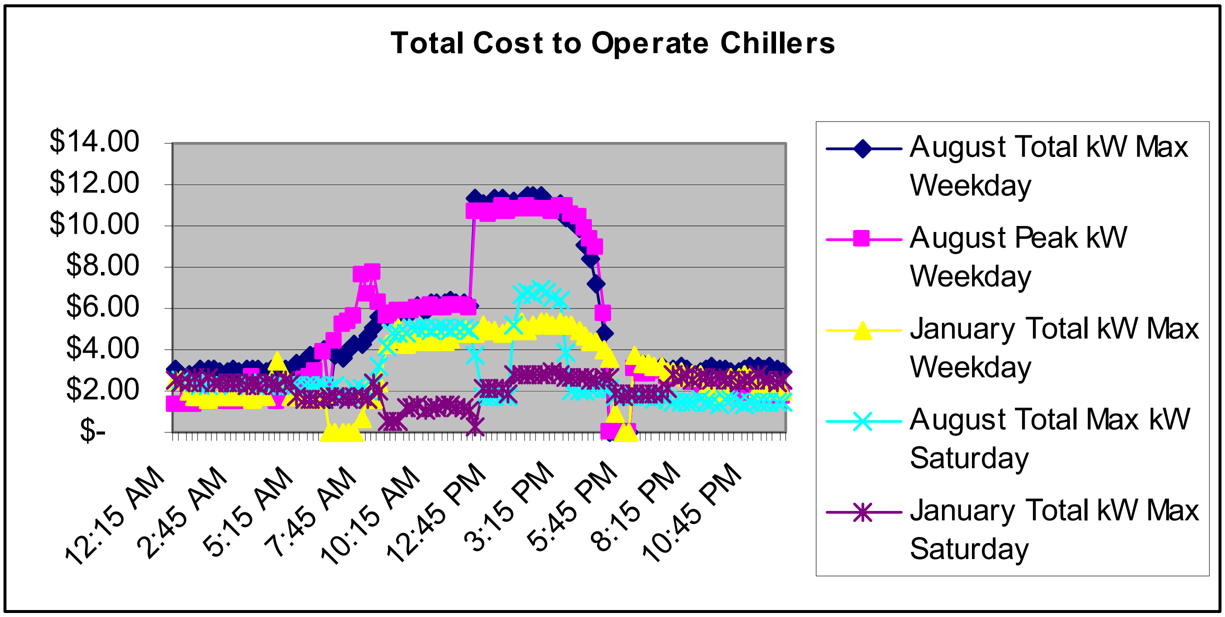


Figure 2.2.2-2: Estimated total cost to operate chillers, $/period

2.2.3 New Generation: PV

The PV array in the DEIS overlay of the sample building is a 107-kW Powerlight system with a Trace inverter. The purchase of PV was an act of environmental good citizenship, which was reported in the press; the decision was not made on the basis of strict economics. The PV cost was approximately $5,000/kW installed. Variations of cloud cover, of course, affect the day-to-day production of the solar array, with the winter months showing greater daily variation.

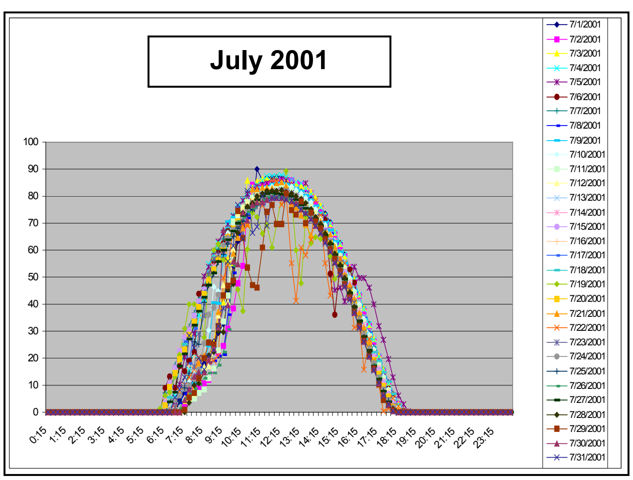


Figure 2.2.3-1: July solar output

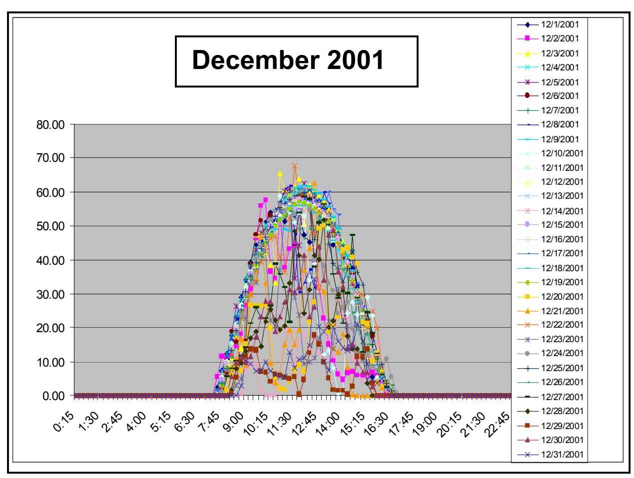


Figure 2.2.3-2: December solar output

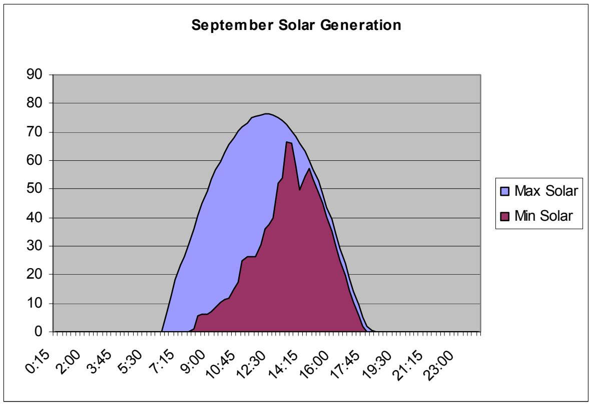


Figure 2.2.3-3: September solar min/max

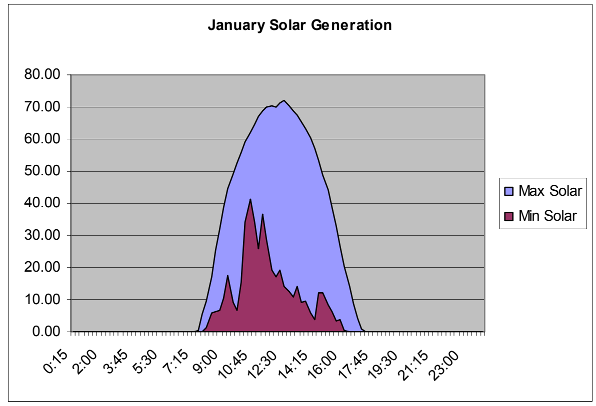


Figure 2.2.3-4: January solar min/max

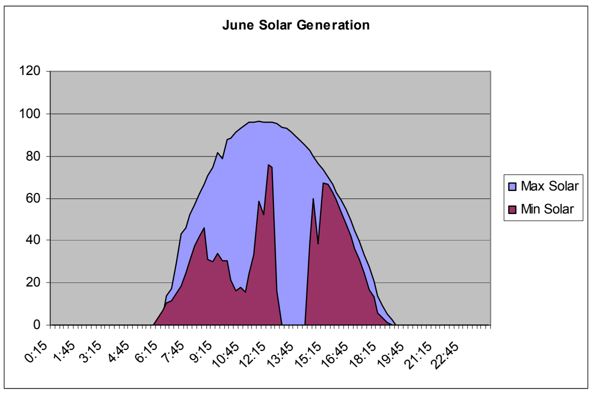


Figure 2.2.3-5: June solar min/max

The efficacy of the solar array varies greatly during the year. The total kilowatt-hours produced during the first year of operation varied between 20,206 in June to 7,390 in November. The unit never produced more than 101 kW — less than 95% of its nameplate capacity — and produced this total only 1 hour of the year. The average kilowatt production during the months of June to August from 11 a.m. until 2 p.m., the peak solar times during the peak solar months, was 81 kW.

2.2.4 New Generation: Internal Combustion Engines

The prime mover for the CHP system is a pair of Hess Microgen model 220s. These are two reciprocating ICEs (called ICE-1 and ICE-2 for the lead and lag engines, respectively) that run on natural gas. The rated output is 200 kW, but the engines can be safely operated at higher kilowatt output levels; the upper threshold of normal operation is 220 kW. The engines are Rich Burn models, using 948 Btu per standard cubic foot low heating value (LHV) natural gas. The Rich Burn model is less efficient electrically and thermally than the Lean Burn model, but it allows operation of a catalytic converter to comply with the strict air quality regulations of South Coast Air Quality Management District. Hess Microgen released a specification sheet containing the following manufacturer data for engine critical functioning:

- Fuel consumption[11]: 35.5 scf/min
- Fuel consumption[12] (therms per hour): 20.2 therms per hour
- Electrical heat rate (100% load): 10,090 Btu/kWh
- Electrical efficiency: 34%
- Thermal efficiency: 48%
- Total combined efficiency: 82%.

[11] Using 948 Btu/scf LHV natural gas.

[12] Same as above.

Manufacturer heat rate data usually do not reflect the actual field operation of a unit. To simulate field operations, this report adds a 5% factor to heat rate, for an estimated field heat rate of 10,650. This higher heat rate degrades the manufacturer efficiency values. New values need not be calculated here, though, because the heat rate becomes the basis for calculating increased fuel consumption at partial loads. (See Section 2.3.5 for a more detailed discussion of the heat rate curve.)

Internal functions of the engines are controlled by an internal microprocessor and proprietary data format. The controller is called CView, and it is a Siemens-based microprocessor and software system. CView contains protection settings that send an alarm or stop operations, depending on the severity of the problem. Critical measurements include:

- If oil pressure <10% of normal operating pressure for >1 second = stop
- If oil pressure >110 psi >10 seconds = alarm
- If combustion air temperature (air box) >130°F >10 seconds = stop
- If total kW <160, >220 >10 seconds = alarm
- If total kW <140 >10 seconds = stop
- If generator voltage A, B, or C <250, >310 >1 second = stop
- If generator voltage A, B, or C <0, >350 >1 second = stop
- If frequency <59.5, >60.5 >1 second = stop
- If cogeneration supply temperature <32° F, >210° F >10 seconds = alarm
- If cogeneration supply temperature >220° F >10 seconds = stop
- If cogeneration return temperature >200° F >10 seconds = alarm
- If cogeneration return temperature >210° F >10 seconds = stop.

Like most bundled manufacturer controls, CView maintains a proprietary internal data language. Interface between CView and PML has disallowed use of the above alarms. Control in the other direction has not allowed engine throttling or other control by PML, except to turn engines on or off. These issues will be discussed in greater detail in Task 4.

2.2.5 New Thermal Supply

The Hess 220s are each rated to produce 978,000 Btus of hot water per hour, or 81.5 tons of chilled water per hour. The maximum flow rate is 60 gal per minute. In actual practice, the engines together have not exceeded 140 tons of cooling per hour delivered to the host building. The maximum water temperature out of the engines, heated by the engine waste heat, is 210°; operational average is closer to 205°. The water is heated both by the engine jacket and the exhaust system.

2.2.5.1 The Absorption Chiller

The absorption chiller, manufactured by Century, is the centerpiece of the thermal supply system that the DEIS controls. Supply and return pipes adjoin it to the engines, the cooling tower, and the building. The chiller controller controls all internal operations of the chiller and ties into the PML generator controller. Inside the absorption chiller are the generator, condenser evaporator, absorber, and solution pump/heat exchangers.

The system uses lithium bromide as the absorbent and water as the refrigerant in an absorption refrigeration cycle. The cyclical process takes place in a sealed, hermetic vessel from which essentially all air has been evacuated. Consequently, the pressures within the shell are the vapor pressures of the liquids at their respective temperatures. In operation, the pressure in the concentrator and condenser sections is about 1/10 of an atmosphere; pressure in the evaporator and absorber sections is about 1/100 of an atmosphere.

The following five steps occur continuously and simultaneously during operation:

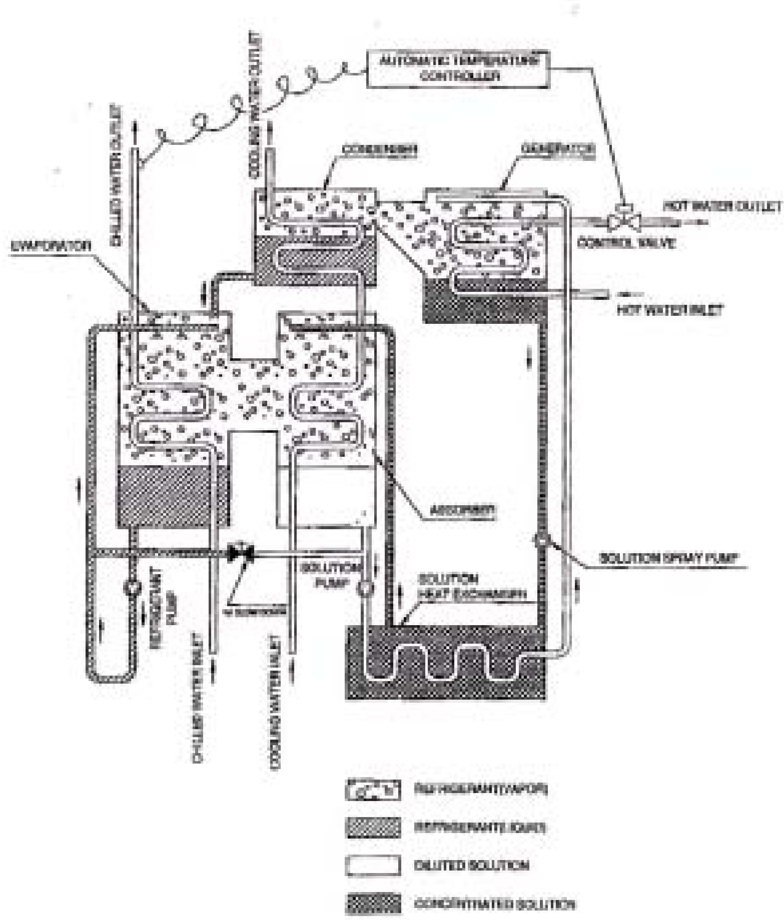


Figure 2.2.4-1: The Century absorption chiller

1. In the generator:
   Heat energy from hot water is used to boil a dilute solution of lithium bromide and water. Boiling releases water vapor and concentrates the remaining lithium bromide solution.

2. In the condenser:
   The water vapor released in the concentrator is drawn into the condenser section. Cooling tower water flowing through the condenser tubes cools and condenses the refrigerant water.

3. In the evaporator:
   The condensed refrigerant water flows though the “U-trap” into the low-pressure evaporator, where “flashing” (a drop in pressure resulting in partial evaporation) cools the remaining water to the saturation temperature at the pressure present within the evaporator, approximately 40º F.

4. In the absorber:
   The refrigerant water vapor is drawn to the absorber section by the low pressure resulting from absorption of the refrigerant water into the lithium bromide absorbent. To expose a large amount of lithium bromide solution surface to the water vapor, the solution is sprayed over the absorber tube bundle. Cooling tower water is used in this tube bundle to

remove the heat of absorption that is released when the refrigerant water vapor returns to the liquid state. As the absorbent absorbs refrigerant water vapor, the solution becomes increasingly dilute.

5. In the solution heat exchanger:
   The solution heat exchanger exchanges heat between the relatively cool dilute solution transferred from the absorber to the generator section and the hot, concentrated solution being returned from the generator to the absorber. Transferring heat from the concentrated solution to the dilute solution reduces the amount of heat that must be added to bring the dilute solution to a boil. Simultaneously, reducing the temperature of the concentrated solution decreases the amount of heat that must be removed from the absorber section.

2.2.5.2 The Cogeneration Loop

The cogeneration loop consists of the cogeneration supply and return, which runs from each of the Hess 220s to the absorption chiller and supplies hot water to the absorption chiller generator. The supply line delivers 205°F water to the absorption chiller. The hot water that is accepted by the supply line valve enters the absorption chiller to produce chilled water. Whatever hot water the valve rejects goes instead to radiators to be cooled and returned to the engines. In either case, the cogeneration return line carries water back to the engines at 165° F.

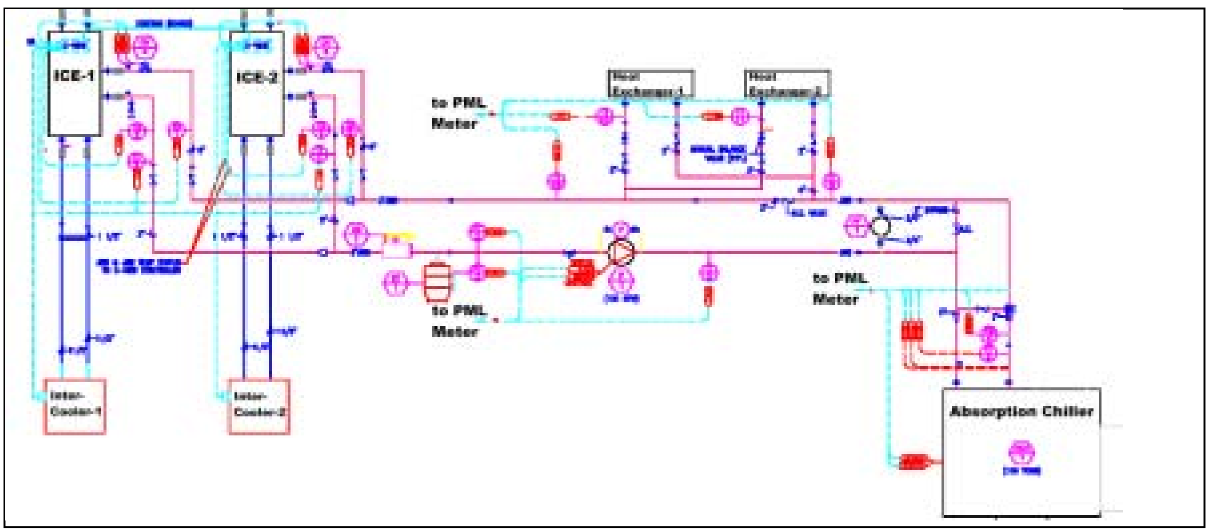


Figure 2.2.4-2: The cogeneration loop

2.2.5.3 The Chilled Water Loop

The chilled water loop runs from the absorption chiller to the building, delivering cooling and returning to the absorption chiller. Building supply should be about 42º F– 45º F when operating. When the building is using all of this for space cooling, the return water will be 7°–10° warmer, about 50º F–55º F. When the return temperature drops, when the building cooling load is dropping, the three-way valve on the cogeneration loop (just above the absorption chiller) will close down so that less hot supply water enters the absorption chiller, and therefore less chilled water is supplied to the building. The excess hot water at the three-way valve then bypasses the absorption chiller and is routed to the balance radiators (labeled HX, or heat exchangers, 1 and

2). The chilled water supplied to the building is a product for which RE bills the host. To determine how much cooling the system supplies, a Btu meter is placed in the chilled water loop. Flow and temperature of the supply and return lines are measured to calculate total ton-hours of cooling delivered. The total bill, equal to ton-hours of cooling delivered multiplied by price per ton-hour, is called the "thermal credit." This is the value to RE of the system heat capture.

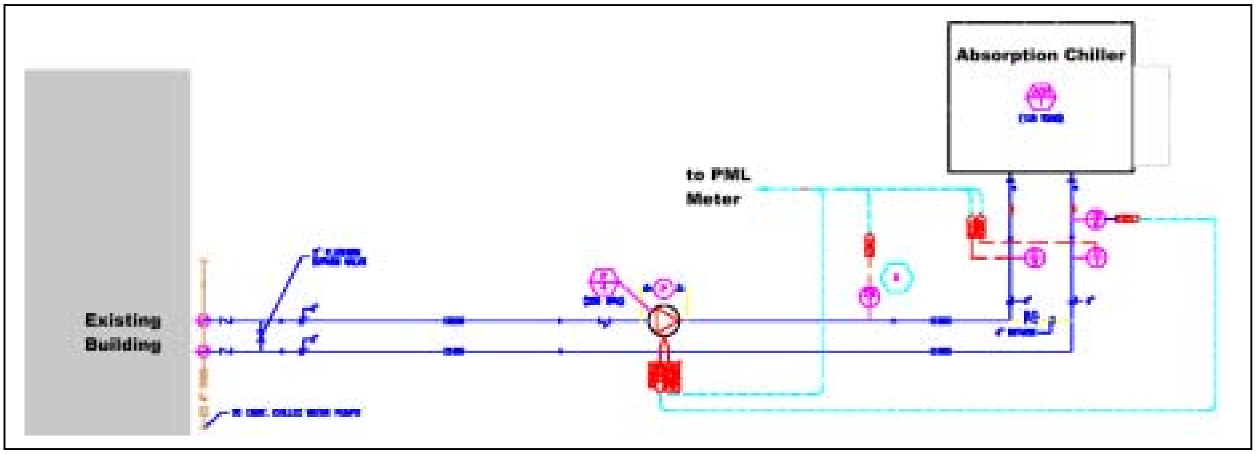


Figure 2.2.4-3: The chilled water loop

2.2.5.4 The Cooling Tower Loop

The cooling tower loop runs from the absorption chiller to the cooling tower. The temperature of supply should remain at about 80° F. During operation, the temperature of the return water gets to 90°F or more. If the cooling tower is not able to supply water cooled to about 80°F, the system modulates the variable frequency drive that controls the condenser fan to further decrease the supply temperature.

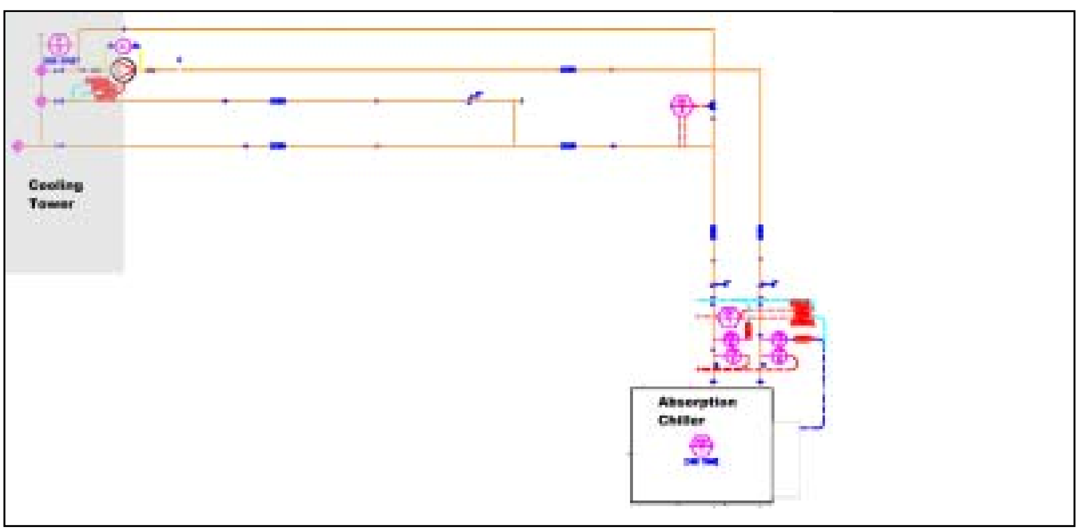


Figure 2.2.4-4: The cooling tower loop

2.3 System Interaction

Components possibly affecting a decision to dispatch include: applicable utility rate tariff, PV day fluctuation, building load curve, the 5% design margin ensuring non-export during load-following, the price of natural gas, prime mover heat rate, the prime mover percentage of full load, and the value of thermal dispatch. Each of these will be described.

2.3.1 Electric Utility Tariff

The building operates under a TOU rate for large customers (greater than 500 kW) called TOU-8. Summer season is defined as 12 a.m. on the first Sunday in June to 12 a.m. on the first Sunday in October; winter is all other times of the year. In summer, the on-peak tariff applies from noon to 6 p.m. on weekdays, excluding holidays. Summer mid-peak is charged 8 a.m. to noon and 6 p.m. to 11 p.m. Winter mid-peak runs from 8 a.m. to 9 p.m. There is no on-peak charge in winter. Summer on-peak $/kWh = $0.1829; summer mid-peak $/kWh = $0.0996; summer off-peak $/kWh = $0.0867. Winter mid-peak $/kWh = $0.1100; winter off-peak $/kWh = $0.0878. Demand charge is not considered in this report.

2.3.2 Building Load Shape Modified by PV

The building shows predictable vertical load increase and decrease correlated to building occupancy (see Section 2.2.1.2, above.) Although the PV kilowatt drop-off is more gradual at the shoulders of the day than the building load, it does fit the load shape of the commercial building occupancy very well on a good solar day at any time of year.

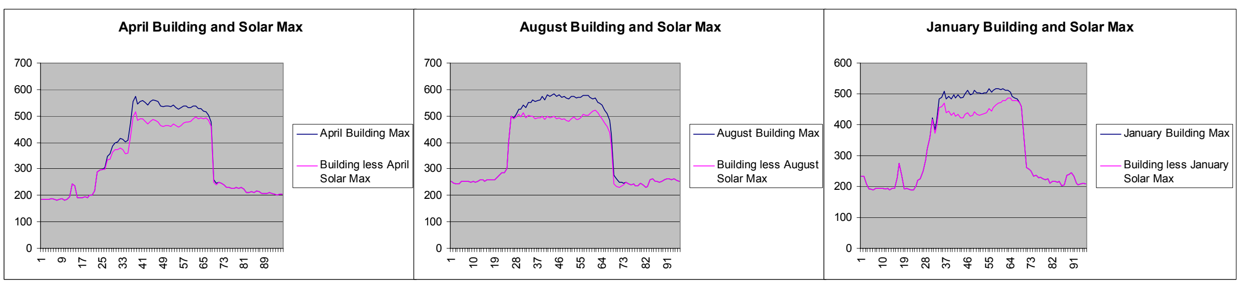


Figure 2.3.2-1: April, August, and January building and solar max kilowatt days

Might fluctuation of PV, exemplified by the minimum solar day in June (Figure 2.2.3-5), affect optimal dispatch? If we superimpose this day on the building load, we see that PV fluctuation actually has very little effect on either the maximum or minimum building load in June.

Figure 2.3.2-2 shows the minimum and maximum solar days superimposed on the building minimum and maximum daily loads. The minimum solar day does nothing to change dispatch. Notice, though, the effect of the maximum solar day on the minimum off-peak daytime building loads. At noon, the solar array reduces the building load from 198 kW to 102 kW, a drop of more than 48%. If, on this day, the ICE is also running, it is clear that the engine would have to throttle down below 100 kW to

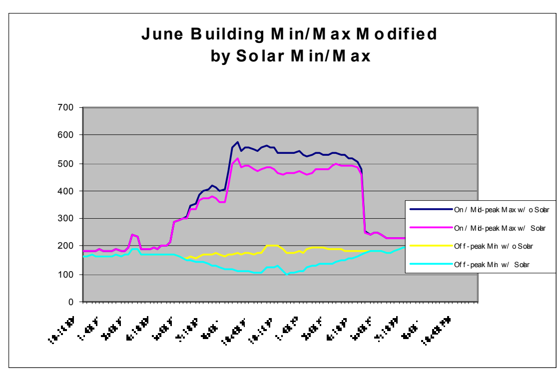


Figure 2.3.2-2: Building min/max modified by solar min/max

accommodate the diminished building load. If the engine operated at a constant heat rate at all points along its load curve, this would not be a problem. However, the engine heat rate rises at partial load. As the engine's kilowatt output decreases, the heat rate to achieve the lower load increases. At a certain point, the engine operational cost will exceed the displaced utility electrical tariff, and the engine will no longer be economical to operate. At that point, either the PV or the engine must be shut off. The choice will depend on economics. On minimum solar days, of course, PV will have little influence, and its position as "base load" can be ignored. The only case in which PV might cause a change of dispatch order is on a maximum solar day on a weekend or holiday (a "non-weekday"). This issue will be discussed in detail in Section 4.

2.3.3 Non-Export

Another significant factor in generation sizing and dispatch is the requirement under Section I of Rule 21 (Screen 2, Option 2) to ensure that non-exporting generators maintain a minimum import of power. Option 2 states:

> To insure at least a minimum import of power, an under-power Protective Function must [be] implemented at the PCC [point of common coupling]. Default setting shall be 5% (import) of DG Gross Nameplate Rating, with maximum 2.0 second time delay.

RE fulfills the device requirements with its PML meter. This under-power protective function is called a Device 37. The PML current transformers fulfill the function of Device 37 by sensing when the incoming power drops below the 5% set point. At this point, RE's units drop off line and remain off line until the building demand goes back up beyond the set point.

The DEIS maintains a second 5% non-export function called the load design margin. Because ICE-1 and ICE-2 each perform the function of a marginal unit at times (ICE-2 is marginal during peak and shoulder periods; ICE-1 is marginal at all other times), it is necessary when building load drops for the system to throttle down below the dropping load to avoid incidental export. The design margin works by requiring the marginal unit to maintain operation at least 5% below the building load. Because there is a lag between the time when the building load drops and the time the DEIS senses the drop and completes throttle-down of the ICE, the design margin acts as a buffer to prevent export during the lag.

2.3.4 The Price of Fuel and Operations and Maintenance

Natural gas prices have been volatile over the past 15 months. In early 2001, the prices caused some electricity suppliers to take unforced outages rather than run generators. Natural gas spot prices climbed to more than $35 per MMBtu in February 2001 in Southern

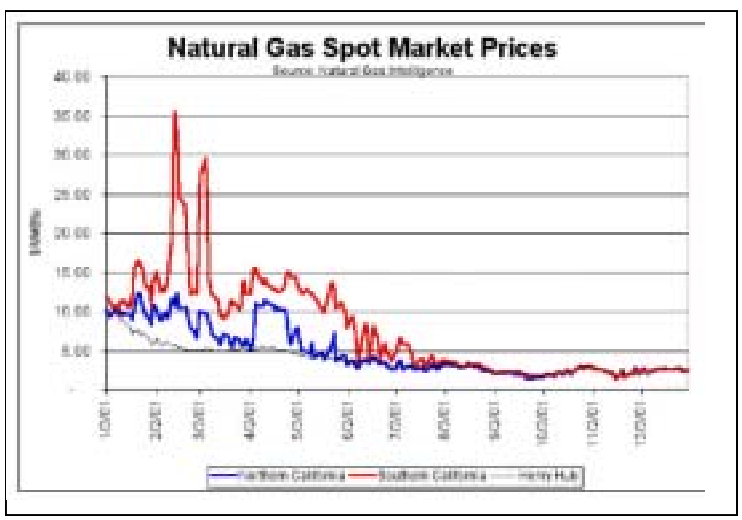


Figure 2.3.4-1: Spot prices for natural gas

California. Spot prices in Northern California peaked at the same time but at $12, just one-third of the Southern California price.[13]

Gas prices do affect dispatch order of natural gas-fueled prime movers, no less for RE than for larger-scale generators operating on a power pool. The cost of gas to the California commercial sector has been less volatile than the spot market but followed the sharp upward trend in early 2001, reaching $13.76 per thousand cubic feet in February.

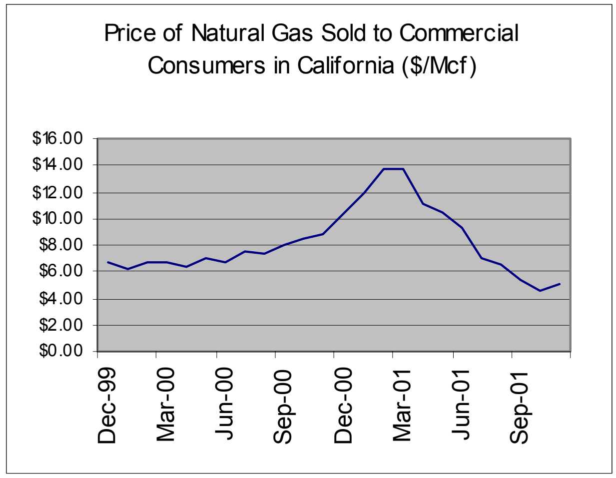


Figure 2.3.4-2: Commercial price of gas, historical for 2000–2001

The price of natural gas is one of the primary inputs to the DEIS for optimal dispatch. To accurately gauge profitability, it is desirable to receive a gas price signal at least once per day. The cost to run the Rich Burn Hess 220 would have been $0.147/kWh in February 2001. Including an industry average O&M cost of $0.015/kWh, the cost to operate rises above $0.16/kWh. Assuming 24-hour operation at 100% capacity by the Hess unit during 2000 and 2001 under a TOU-8 rate at a heat rate of 10,650 Btu/kWh, the unit would operate profitably approximately 57% of the hours of those two years. In 2001 alone, the number drops to 39%.

In the case of RE's current operations, though, there has not been enough gas consumption at most sites or in aggregate throughout the portfolio to warrant moving the projects off of the CORE gas service rate. CORE rate is essentially the bundled gas service offered to residential and small commercial clients. Although this service has locked RE into higher gas rates than have been available on the market, it also mitigates exposure to market price fluctuations.[14]

[13] Natural Gas Intelligence, March 2002, Monthly Report. The report is on the California Energy Commission Web site at http://www.energy.ca.gov/naturalgas/2001_weekly_updates/.
[14] Most installers of cogeneration smaller than 1 MW will elect to choose the CORE rate because they will not consume enough natural gas over the course of monthly operations to qualify for any other type of service.

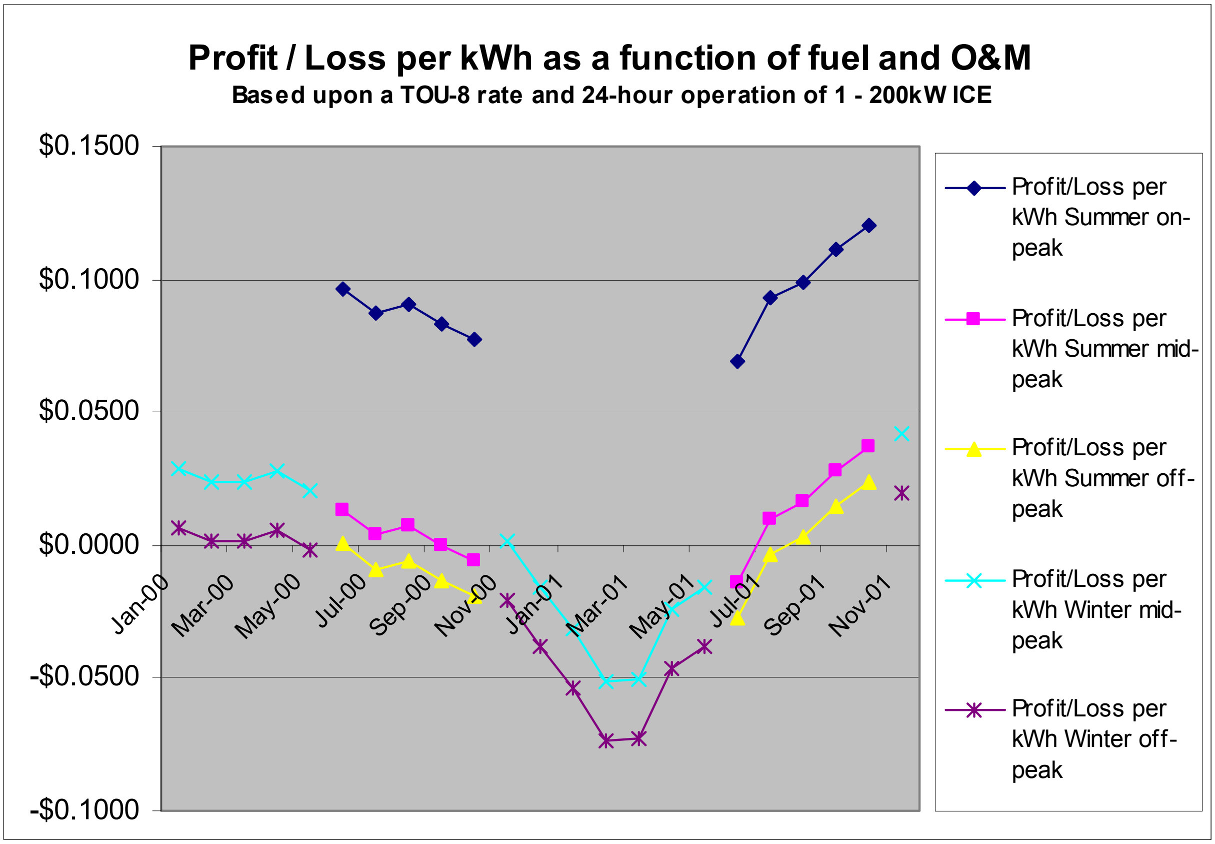


Figure 2.3.4-3: Profit/Loss as a function of fuel and O&M

2.3.5 Engine Heat Rates

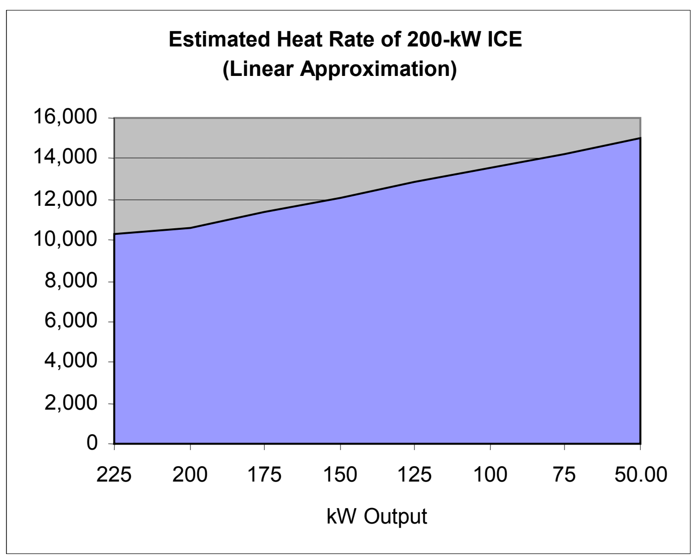


Figure 2.3.5-1: ICE heat rate (linear approximation)

2.3.5.1 ICE Heat Rate Curve

Optimal dispatch requires flexibility in the operation of ICE-1 and ICE-2. The latter, as we shall see, will act as the marginal unit during most mid- and on-peak times; the former will act as the marginal unit during off-peak times. Throttle control of the engines will be necessary to maximize project profitability and to avoid incidental export. As the engines throttle down from full load, however, heat rate and engine efficiency deteriorate. When the engine reaches 50 kW, or 25% of load, the heat rate is as high as 15,000 Btu/kWh, about 22.8% efficiency. The heat rates between 25% and 100% typically form the "heat rate curve," approximated here by linear interpolation, which gives a more conservative number in proxy for actual measurements. As the quantity of fuel consumed per kilowatt rises, the cost per kilowatt-hour to operate the ICE rises also.

2.3.5.2 Effect of Heat Rate on Cost to Operate

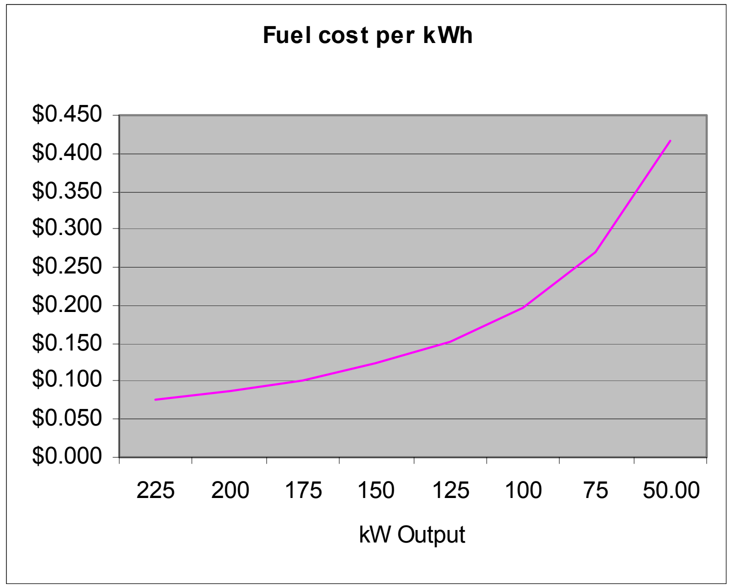


Figure 2.3.5-2: Fuel cost per kilowatt-hour at partial load

Engine efficiency is critical to the profitability of any fossil-fired prime mover because fuel cost is a major cost component in an operation, especially one that is highly automated, as is the DEIS.[15] Efficiency is critical to RE operations; it is one of the biggest factors in operational profitability. The engine fuel consumption along its operable range and the cost of gas are the two determinants of fuel cost per kilowatt-hour. Figure 2.3.5-2 shows the fuel cost per kilowatt-hour geometrical curve along the approximated linear heat rate. The chart assumes natural gas price at the March 2002 level of $6.71/mcf (1,000 cubic feet).

2.3.5.3 Throttle-Down Thresholds

Figure 2.3.5-2 shows clearly how fuel costs per kilowatt-hour increase at lower load levels. It is easy to imagine that for each tariff there will be a point on the kilowatt output curve where it will no longer be profitable to operate. The five break-even points (one for each tariff level) at each kilowatt output level are called Throttle-Down Thresholds. (See Figure 2.4.5-4 for a mapping of the Throttle-Down Thresholds across a range of kilowatt output levels.) The thresholds are calculated as follows:

1. The manufacturer's specified rate for fuel consumption at 100% load (35.5 scf/min) is divided by the simulated heat rate (10,650) to get a ratio of fuel consumption to heat output (0.0033).
2. The cost for natural gas ($/mcf) is divided by 1,000 to get $/scf.
3. Fuel consumption per minute is multiplied by 60 to get fuel consumption per hour; this is multiplied by $/scf to get cost $/hr.
4. Kilowatt output (% load * 200 kW) is divided by 1 hour to get kW/h.
5. Divide $/hr by kWh to get cost $/kWh.
6. Adjust kilowatt output until $/kWh = rate tariff level; that kilowatt output is the Throttle-Down Threshold for that rate tariff level. Do this for each rate tariff level.
7. To get the next value, multiply the heat rate of the next load percent by the fuel consumption heat output ratio (0.0033).
8. Repeat steps 3–7 until all kilowatt values are calculated.

[15] The future of DER will very likely see an increase in automation of resource operations, particularly with multiple generators across multiple facilities.

2.4 Optimal Dispatch

Given this, it is possible to formulate optimal dispatch. Economic dispatch is the system used by major power pools in the United States. The dispatch order of specific units is proprietary information because if an operator knew marginal prices, it would have a competitive advantage.

2.4.1 Relative Installation and Operating Costs

The situation with a network of distributed generators in a single building is somewhat different, though some principles remain the same. As in the traditional power pool, dispatch decisions are made on total cost to operate (economic dispatch). Cost to operate is still proprietary, not because of possibilities of gaming but for strictly competitive reasons. Although dispatch is still economic, it is not necessary to know actual operating costs to formulate it. It is possible to optimize dispatch knowing the relative magnitude of costs, including operational cost considerations, in relation to one another.

In a system involving only engines and PV, as we are considering, the relative magnitude of costs is simple. PV is very expensive to install, costing $5,000 per kilowatt or more. Once installed, though, fuel is free, and operation costs are zero. Maintenance costs have not yet been calculated. Although the costs appear to be low, there are complications, as mentioned above. RE has not yet calculated its internal O&M cost for PV; no O&M cost for PV is included in this analysis. PV fits the profile of a base-load unit in a traditional power pool: expensive to build, cheap to run. Engines are relatively inexpensive to purchase and install (less than $2,200/kW installed) and are more expensive to run. Engines fit the mold of the traditional marginal or peaking unit.

2.4.2 Dispatch Stratification

These considerations, though, point out paradoxes that do not fit traditional dispatch on a power pool. First, PV are not really base load because they only operate during limited daylight hours (5:15 a.m. to 6:45 p.m. on the longest day of the year). Therefore, "base load" cuts out at night, though as we've seen, the building continues operating at a significant load — 35% of average maximum — during the night.

The second paradox is that cogeneration is not a peak load strategy; it is a base-load strategy, on account of on-site thermal loads. For this reason, cogeneration is usually not a good option for an application that operates less than 40%–50% of the hours of the year.

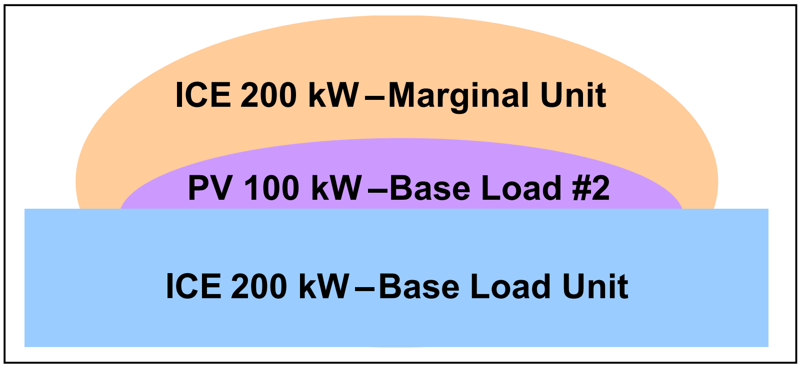


Figure 2.4.2-1: Proposed dispatch stratification

Engines are the only available generation (in the site example chosen for this report) capable of providing electricity and cooling during off-peak hours. Therefore, the marginal unit technology must also act, in this case, as the base load unit technology. Using two engines, it is possible to envision the dispatch stratification of ICE-1 as 24-hour base load, PV as daytime base load, and ICE-2 as daytime marginal unit.

This scenario will require throttle control in the off-peak to run the ICE base load unit at 160–190 kW to avoid incidental export. An alternative to a non-export agreement with the utility would be an incidental export agreement. The question is whether it is more economical to overproduce and allow incidental export or to use throttle control to reduce generator output, increase heat rate, and incur higher costs per kilowatt-hour. Besides throttling down in the off-peak, the ICE marginal unit would have to make up for deficiencies in PV output and for mid- and on-peak load plunge when the large chiller shuts off.

2.4.3 Limitations of ICE as a Marginal Unit

Throttle control is currently handled for the Hess 220 by a Woodward EGCP-2, a microprocessor-based engine generator control and energy management device. Key functions of the Woodward are engine control, synchronizing, real kilowatt load control, protection functions for interconnection, and communications. This throttle control does not allow operation at partial load, nor does it allow automatic control by PML. RE is currently installing a "Murphymatic" throttle control in the project buildings. Neither the existing Hess throttle nor the Murphymatic can follow load because they do not have the operational flexibility to make the small adjustments in kilowatt output required to maximize profitability. The Murphymatic is more flexible than the Hess controller, allowing three control positions other than 100% or 0%. It remains to be seen whether the Murphymatic can handle daily Throttle-Down Threshold value changes during the two daily rate tariff periods (in winter) or three daily rate tariff periods (in summer). An optimal throttle control would be able to follow load in arbitrarily small increments, down to a point at which it is no longer profitable to operate because of the tariff schedule, O&M, and fuel at a higher high heat rate. This is the control that will be assumed for optimal dispatch. The profitability of good throttle control should drive the search for the most incremental throttle control at the lowest price. Documentation of this effort is in Task 4.

2.4.4 Thermal Dispatch

As with PV, once the cogeneration package, absorption chiller, and piping has been installed, running the absorption chiller provides energy for "free." And as with PV, there are maintenance costs that prevent the true cost from actually being zero. But the hot cogeneration water that drives the absorption chiller is free fuel, the capture of waste heat from the engine jacket and exhaust. All Btus delivered to the building as chilled water that do not return to the absorption chiller displace Btus the building chillers would have to supply. There is no reason, from the perspective of thermal dispatch, not to run the absorption chiller at all times that there is a cooling load in the building.

At least two scenarios are imaginable, however, in which the thermal dispatch mandate to run must be overruled. First, it should be overruled when the cost to operate the engine exceeds the chargeable rate tariff plus the value of the chiller displacement. Thermal dispatch should also be overruled when operational conditions prevent safe or economic dispatch. This would include all exceptional times when the system is malfunctioning. For the purposes of optimal dispatch, we will ignore this second point except to include alarms for improper system functioning.

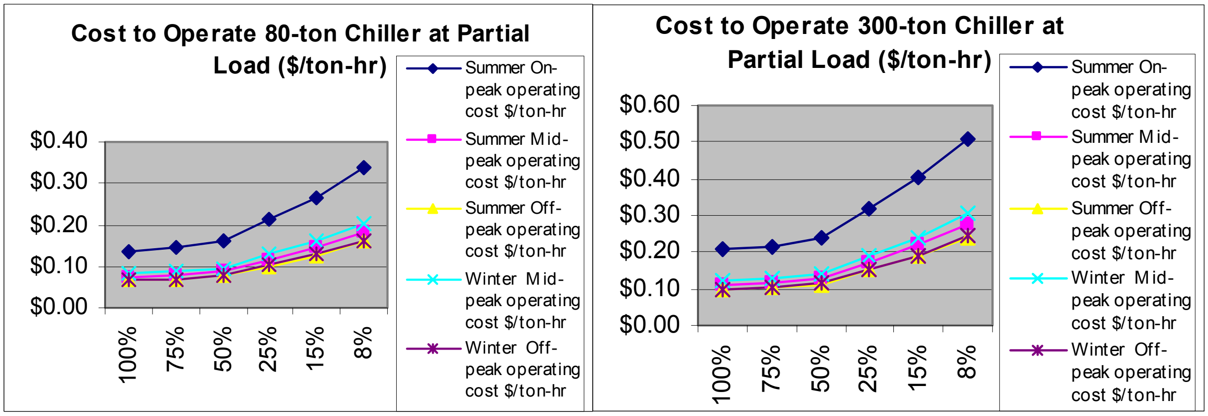


Figure 2.4.4-1: Cost to operate 80-ton and 300-ton chillers

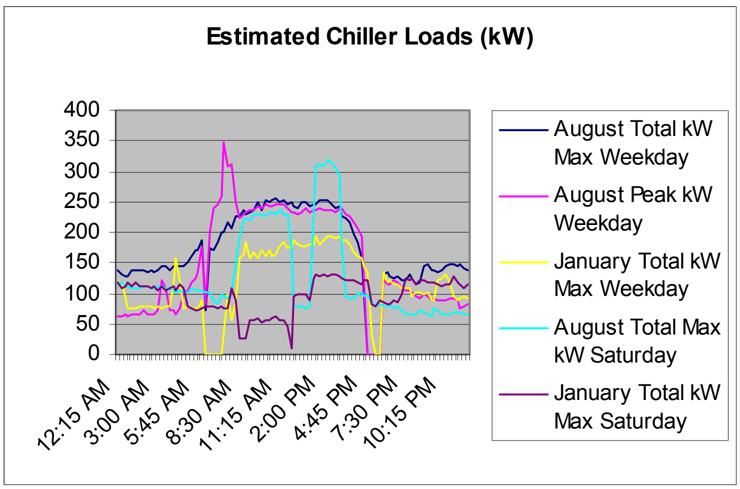


Figure 2.4.4-2: Estimated chiller loads

The value of thermal dispatch to the host customer is determined by the cost to operate the building chillers because this is the load that is (partially) displaced by the absorption chiller. This value should drive the customer decision to install CHP in the first place. Figure 2.2.2-2 shows the cost to operate the two existing building chillers. The cost to operate the chillers on a per-ton-hour basis depends on the percentage of full load at which the chiller operates.

Subtracting the estimated constant loads of the building from total building load gives the estimated chiller loads on a 15-minute basis. We will compare 3 sample days in August and 2 sample days in January: (1) the maximum total kilowatt weekday in August (when average kilowatt demand is highest), (2) the peak kilowatt day in August (the highest kilowatt demand of the year), (3) the maximum total kilowatt Saturday in August (when non-weekday kilowatt demand is highest), (4) the maximum total kilowatt weekday in January (when average kilowatt demand is highest), and (5) the maximum total kilowatt Saturday in January (when non-weekday kilowatt demand is highest). January is selected as the minimum load month. Saturdays are selected to demonstrate optimal chiller dispatch on marginal use days. These days are used as examples of the comparison of the cost to run the building chillers before and after the addition of the absorption chiller.

Recall from Section 2.2.2.2 that existing building chiller dispatch requires that the 80-ton chiller serve as the base load chiller because it is less expensive to operate. The larger chiller serves as the marginal chiller, following the cooling load above 80 tons. This is not an ideal situation: the 300-ton chiller runs an average of 94% of the hours of the day at an average load of only 76 tons, 25% of capacity. We can see from the chiller chart in 2.2.2.2 that this is 1.75 kW per ton average efficiency — very poor. Building engineering embraces the CHP project not only for increased electric reliability but because it allows them to use the "free" cooling from the absorption chiller as the base load and to run the 80-ton chiller as the "marginal cooling unit." The 300-ton chiller is then held in reserve for occasional peak cooling.

This scenario gives us the displaced cost (savings) of the absorption chiller on the three weekdays and two non-weekdays. The five weekdays are:

1. The highest kilowatt usage total day of the year (called August Max Weekday)
2. The peak kilowatt usage of the year (called August Peak Weekday)
3. The maximum kilowatt winter weekday for the month (January) with the minimum kilowatt peak (called January Max Weekday)
4. The highest kilowatt usage total non-weekday in summer (called August Max Saturday)
5. The highest kilowatt usage total non-weekday in winter (called January Max Saturday).

The days were selected to give both seasonal and operational minimum/maximum limits on days when there is building occupancy. (Sundays and holidays have flat building load shapes, which do not inform us about chiller usage.) Total cost savings from thermal dispatch of the absorption chiller for the five sample days are significant.

Note that the "Savings to CHP Customer" listed in Table 2.4.4-1 is the value to the building owner of the absorption chiller — i.e., the reduction in cost to cool the building. Although this value will drive customer desire for and satisfaction with the installation, it is not the same as the thermal credit discussed in sections 2.2.5.3 and 2.4.5.2. The thermal credit is an input into dispatch, a "supply-side" number, which is the value to RE of the absorption chiller — the amount of revenue that can be billed to the customer for providing building cooling. It will be important to make sure that optimal dispatch is optimal both for the customer and for the distributed energy supplier.

Table 2.4.4-1: Estimated Savings from Absorption Chiller

Sample Day	***Cost Before Abs Chiller***	***Cost After Abs Chiller***	***Savings to CHP Customer***	***% Savings***
August Max Weekday	$488.93	$106.52	$382.41	78%
August Peak Weekday	$449.68	$112.73	$336.95	75%
January Total Weekday	$289.34	$67.06	$222.28	77%
August Max Saturday	$269.09	$79.92	$189.17	70%
January Max Saturday	$203.39	$51.77	$151.62	75%

** Does not include demand savings*

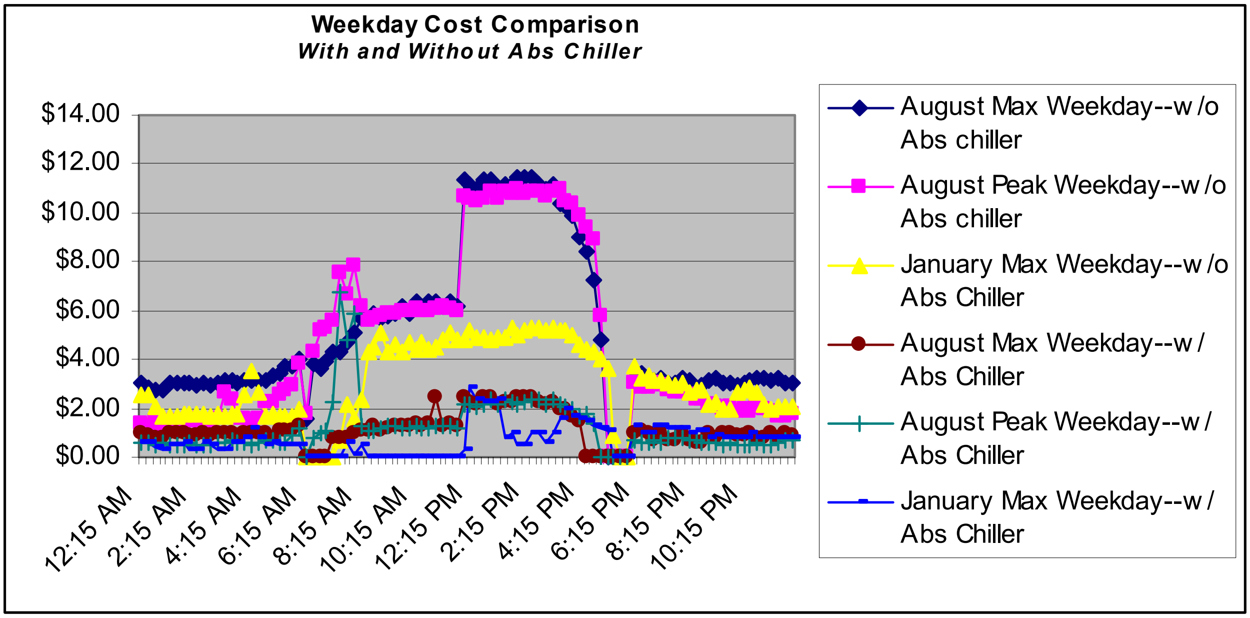


Figure 2.4.4-3: Weekday cooling cost comparison

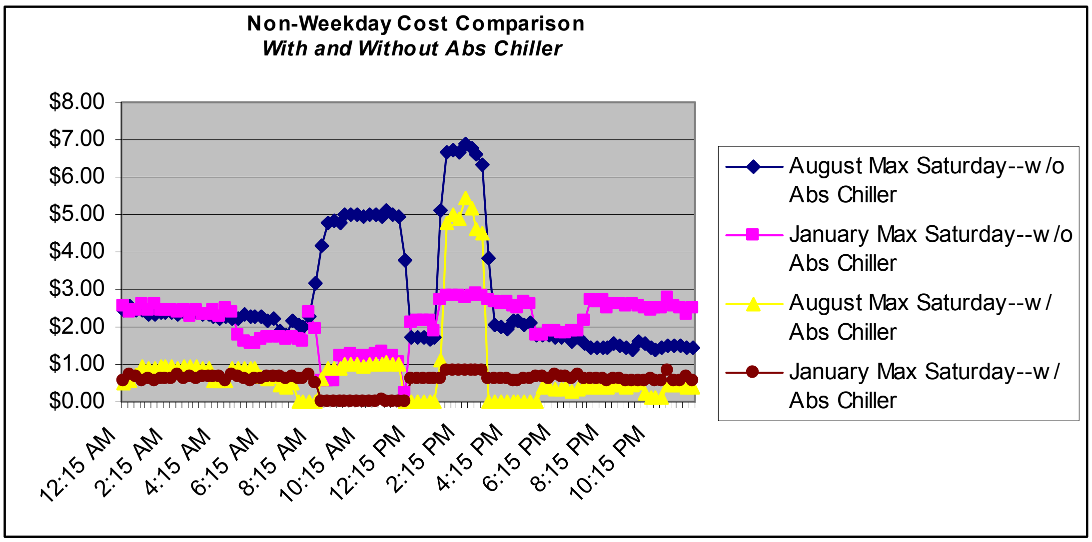


Figure 2.4.4-4: Non-weekday cooling cost comparison

2.4.5 Composite Views of PV, ICE, and Building Load

To model the result of the assumed dispatch (ICE-1 for off-peak base load, PV for on- and mid-peak base load, and ICE-2 as marginal unit), we will model a composite of these three systems, considering electric[16] and thermal dispatch.

[16] All cost figures use the March price for natural gas of $6.71. In dynamic operation, the DEIS will gather daily gas prices and use these for calculating dispatch and operating thresholds.

2.4.5.1 Normal Operation

The dispatch modeling for normal operations should cover typical weekday operation, including days of minimum and maximum load, during all months of the year. If the dispatch stratification outline in Section 2.4.2 still holds, we will assume that this is the optimal dispatch for normal operations. In the first scenario, we ignore throttling to see where and when throttle control should be applied. The dispatch algorithm simply states that if the load is less than 400, run ICE-1 and PV at maximum. The PV numbers assume the best solar day. For days of maximum load, the load is positive in 88% of the periods (i.e., there is no need to apply throttle control). Considering weekdays only, all occurrences of negative load occur in the off-peak. For days of maximum load, throttle control must be applied in 28% of the off-peak periods.

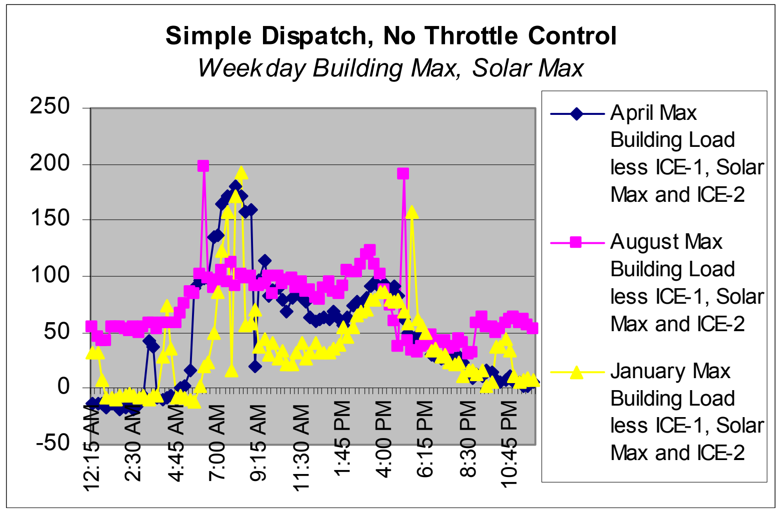


Figure 2.4.5-1: Simple dispatch: building max, solar max

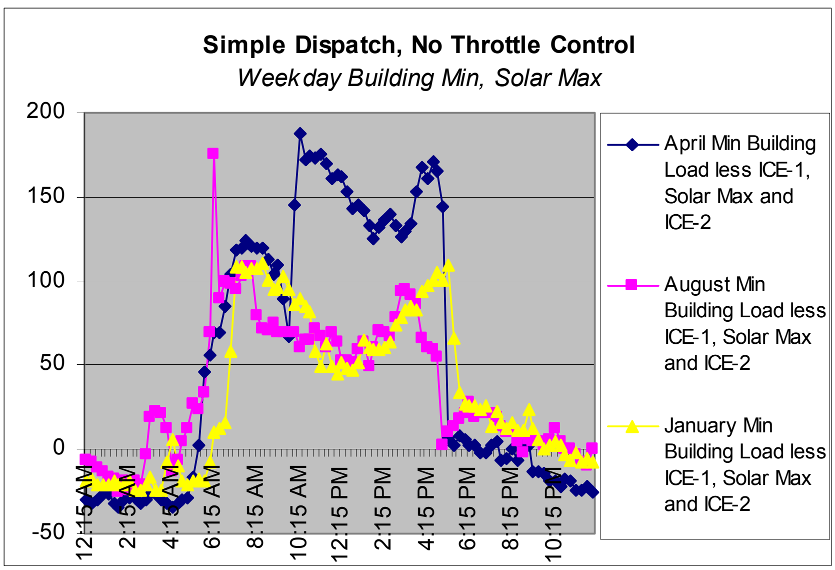


Figure 2.4.5-2: Simple dispatch: building min, solar max

Under minimum building load conditions in these same months, again assuming the max solar day and the simple dispatch algorithm stated above, negative load would occur in two-thirds of off-peak periods, and throttle control is necessary. Load is negative in 7% of mid-peak hours and 0% of on-peak hours. The optimal dispatch algorithm, then, will throttle down ICE-1 during off-peak periods on weekdays. At these times, ICE-1 will follow load, operating as the marginal unit.

2.4.5.2 Exceptional Operation

There were several exceptions touched on earlier that must now be resolved by dispatch modeling. First, recall from Section 2.3.2 that a maximum solar day occurring on a weekend or holiday lowers the load from its off-peak minimum. If the engine attempts to throttle down, it is likely to operate uneconomically because it will be too high on the heat rate curve (see Section 2.4.3). Any solar contribution of more than 60 kW in the off-peak is likely to lower the off-peak building load enough to make ICE-1 operate below the Throttle-Down Threshold (see Figure

2.4.5-4). It is necessary to determine whether this effect should trip the PV so that the ICE-1 can continue base-load operation or whether ICE-1 should shut off, allowing the building small chiller to carry the thermal load and the PV to reduce the electric load. To assess these two operating procedures, we'll use the minimum off-peak day, a Sunday in June, and the solar maximum day, also from June. The price for natural gas used for purposes of these calculations is \$6.71/mcf. To achieve optimal dispatch, the DEIS should know daily gas prices to achieve acceptable granularity.[17] Analysis of the cost to throttle below 100% of full load confirms that operation of both ICE-1 and PV on weekends and holidays will reduce building load below the Throttle-Down Threshold. The operational question to answer is whether it is preferable to operate the PV with the ICEs shut down or whether to trip the PV and allow ICE-1 to run. The answer depends on whether the value of the thermal credit is great enough to overcome the fuel and O&M cost to operate.

The procedure for calculating optimal dispatch is as follows:

1. Record building load per period[18]; subtract 5% for design margin.
2. Calculate the cost per kilowatt-period to operate the engine at the kilowatt level from Step 1. [To calculate cost per kilowatt-period, follow steps 2–5 listed under Section 2.3.5.3 under Throttle-Down Thresholds; divide the result (\$/kilowatt-hour) by 4 to get \$/kilowatt-period.]
3. Calculate O&M cost per kilowatt-period by dividing O&M cost (\$0.015/kWh) by 4.
4. Calculate the total cost per kilowatt-period by adding the results of Step 2 and Step 3.
5. Calculate net earnings per period by multiplying the result of Step 4 by the period kilowatts.
6. Perform the above calculations for: no solar day (PV tripped), maximum solar day, and minimum solar day.
7. Calculate the thermal credit by multiplying the ton-hours of cooling produced by the price per ton-hour. The assumption in this example is that the absorption chiller runs flat-out but the engine is only running at partial load (<180 kW) and therefore can only produce 61.25 tons per hour rather than the manufacturer-rated 81.5. If the absorption chiller did not cover this load, it would have to be covered by the 80-ton chiller at a cost per ton-hour in the summer off-peak of \$0.0651.

Summing the periods of the day gives the following results:

- The no-solar, solar-max, and solar-min days all show negative earnings prior to adding the thermal credit.
- The thermal credit (value of absorption chiller) is \$95 for the day.
- The max-solar day earnings, including thermal credit, are \$18.
- The min-solar day earnings, including thermal credit, are \$28.
- The no-solar day earnings, including thermal credit, are \$35.
- The max-solar day earnings without ICE are \$70, but foregoing the thermal credit; replacement of the thermal credit would make those earnings negative (-\$25).[19]

[17] On CORE rates, gas prices will only vary daily based on demands. Prices may be trued up at the end of the month when imbalance costs finally become apparent; "real-time" true up is not possible on CORE rates.

[18] A period = 15 minutes; there are 96 periods per day. DEIS records building load information by period.

- Optimal dispatch would shut off the ICE when the period earnings from the PV exceeded the value for the period of the thermal credit.
- Optimal dispatch would result in the ICE being shut off from 7:30 a.m. until 4:30 p.m. (on the particular Sunday in question).
- Optimal dispatch would result in earnings for the day of $45.
- Optimal dispatch, on marginal days such as this one, will have to balance the value of the thermal credit, less costs and the non-export design margin, against the value of the PV generation on a particular day.

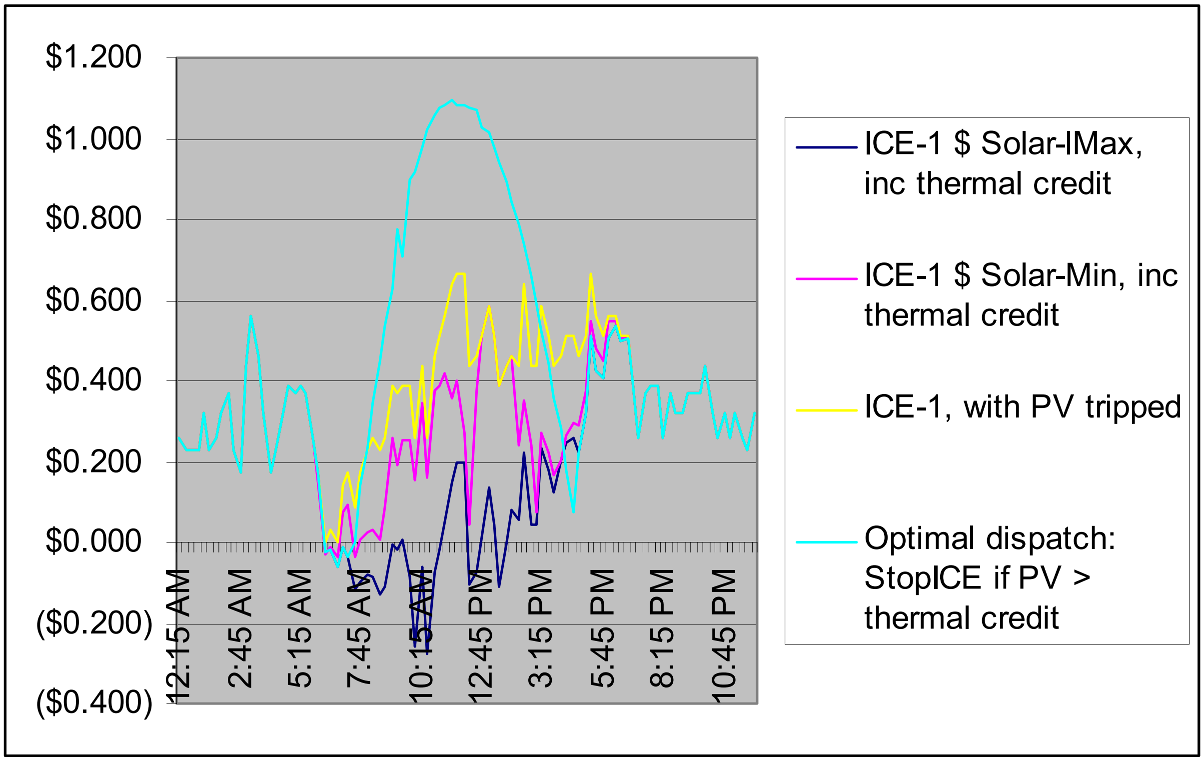


Figure 2.4.5-3: Earnings per period on a Sunday in June

Because the ICEs operate as marginal units most of the time (ICE-2 is marginal on- and mid-peaks, ICE-1 is marginal off-peak), the profitability calculation will be derived from a threshold kilowatt limit below which the engines cannot operate profitably on a given day during a given rate tariff period. The kilowatt profitability level below which any ICE operation will be unprofitable is the Throttle-Down Threshold (see Section 2.3.5.3). Considering the estimated heat rate curve, a constant gas price of $6.71/mcf, O&M costs, a 5% design margin, and the TOU-8 rate tariff for energy, the thresholds for ICE-1 and ICE-2 are as shown in Table 2.4.5-1.

[19] In fact, the loss to the customer would probably be greater because the value of the CHP displacement of its system is greater than the thermal credit.

Table 2.4.5-1: ICE Throttle-Down Thresholds

Applicable Tariff Period	Minimum Threshold kW
Summer on-peak	111
Summer mid-peak	184
Summer off-peak	205
Winter mid-peak	171
Winter off-peak	204

** At $6.71/mcf for natural gas*

This means that at any event, whether it is building load plunge (because of large chiller or lighting shut off or another event scheduled or non-scheduled) or building load displacement by PV, the marginal ICE (whether ICE-1 or ICE-2) cannot throttle down below this threshold, or the electric generation will become unprofitable. It may be desirable to operate below the Throttle-Down Threshold *if* the thermal credit will more than make up the loss. Optimal dispatch will need to recalculate the Throttle-Down Threshold for each period of the day, both on weekdays and weekend/holidays. When the total building load approaches the threshold (say, within 2%), the system will calculate the thermal credit and make a decision whether to shut down the marginal ICE unit or (on weekends during daytime) whether to shut down the PV. If ICE-2 is marginal, this decision is likely to shut off ICE-2 — and this event will happen each weekday. The threshold value will depend on: (1) the price of gas, (2) the cost of O&M, (3) the 5% design margin, (4) the value of CHP thermal dispatch, (5) the applicable tariff, (6) the gross building load, (7) the strength of the solar day, and (8) the engine heat rate curve. The price of gas alone has a significant effect on the Throttle-Down Threshold and can, as shown, make operation unprofitable at any time of day.

It may be possible in future operations to run both engines as "two halves" of a larger system, using throttling on both machines to optimize load coverage. Then, for example, each unit could operate at 140 kW to cover a 280-kW load (not including a design margin). This analysis of the system, however, takes as a limitation the separate operation of ICE-1 and ICE-2 and dispatches these units discretely.

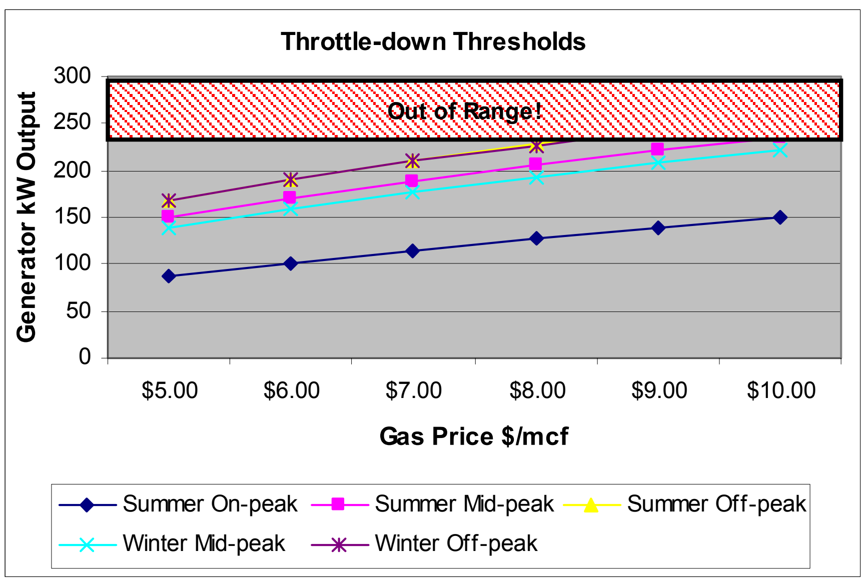


Figure 2.4.5-4: Gas price effect on Throttle-Down Threshold

2.4.6 Optimal Dispatch Flowchart

Given this analysis, it is possible to formulate the flow control for optimal dispatch.

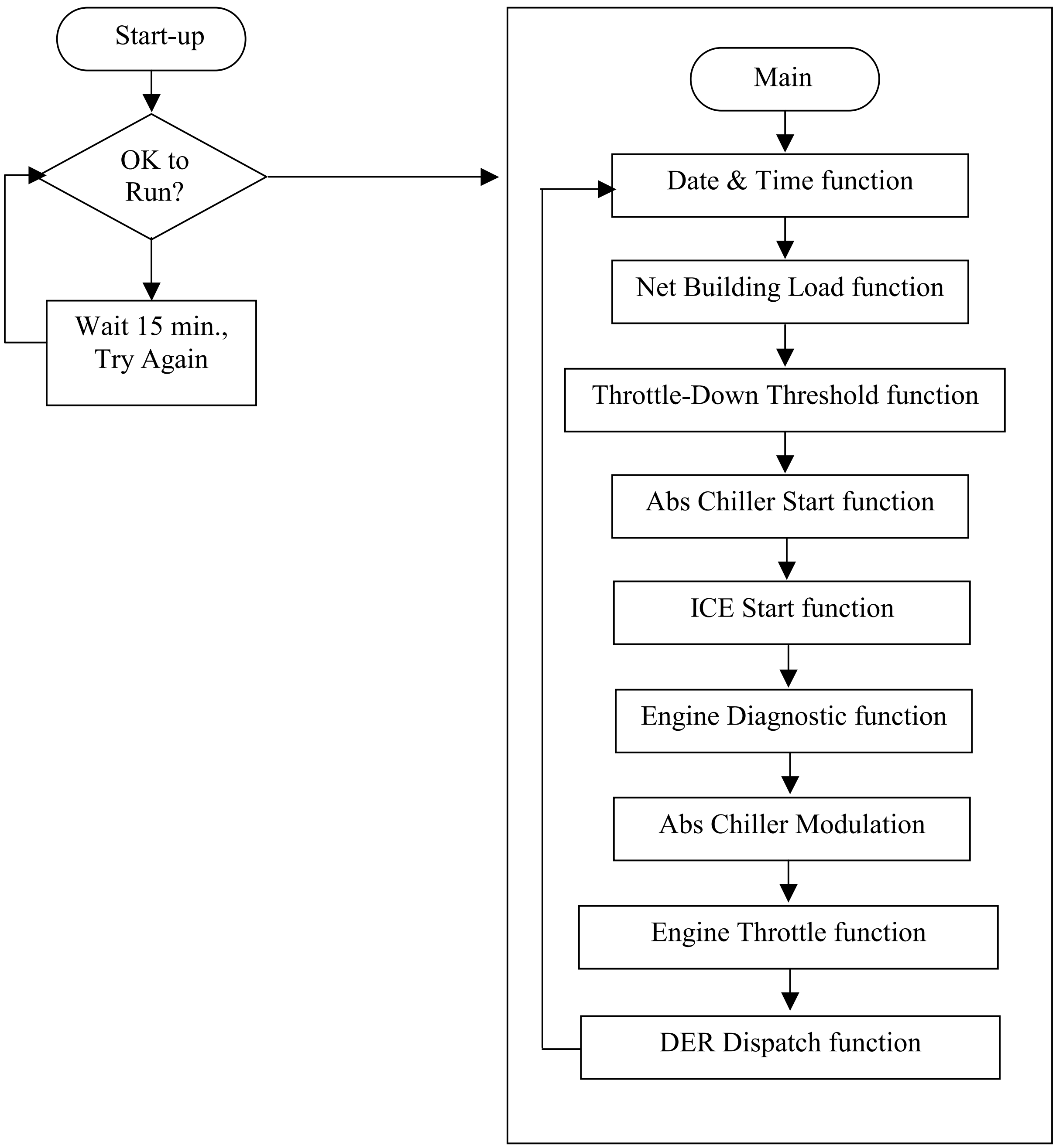


Figure 2.4.6-1: Optimal dispatch flowchart

2.4.7 Optimal Dispatch Flow Logic

The test below is presented to walk the reader through the steps.

Begin Start-up function
Output: Request OK to run generator flag status from host building control
Input: Receive OK to run generator flag status from host building control
Decision: Is OK to run generator flag status true?
  Yes: Continue
  No: Alarm, wait and try again in 15 minutes.
End Start-up function

Begin Main function
Decision: Is it either start-up or top of the hour?
  Yes: Call Date and Time function
  No: Continue
Process: Calibrate the PML meters' time, date, and tariff so as to optimize operations
Decision: Is current clock time within scheduled time of use?
  Yes: Continue.
  No: Wait and try again in 15 minutes
Process: Call Net Building Load function. Calculate the gross building load and automatically gauge the impact of solar production. Determine Net Building Load.
Decision: Call ICE Throttle-Down Threshold kilowatt function
Process: Determine cost per kilowatt-hour to operate at 1-kW increments along heat rate curve, including fuel and O&M cost. Determine point on heat rate curve at which cost to operate exceeds chargeable rate tariff for each rate tariff applicable today. Multiply each of these kilowatt values by 105% for non-export design margin. Assign results to off-peak Throttle-Down Threshold, mid-peak Throttle-Down Threshold, and on-peak Throttle-Down Threshold
Process: Call Abs Chiller Start function

Begin Abs Chiller Start function
Decision: Is Cogeneration Supply Water pump amps >1.0?
    Yes: Continue
    No: Alarm
End Abs Chiller Start function

Decision: Call ICE (1-n) Start function

Begin ICE Start function (Throttle-Down Threshold, ICE generating capacity)
      Process: Verify OK to run flag status by finding out the number of ICEs running and kilowatt output and assessing the kilowatt output of ICEs from generation capacity against the + Throttle-Down Threshold <total ICE generator capacity.
End ICE Start process, alarm if outside parameters

Begin Engine Diagnostic test function
      Decision: Is oil pressure <10% of normal operating pressure for more than 1 second?

Decision: Is oil pressure >110 psi for 10 seconds?
Decision: Is combustion air temp >130°F for ≥10 seconds?
Decision: Is kilowatt total output <160 or >220 for ≥ 10 seconds?
Decision: Is kilowatt total output <140 for ≥ 10 seconds?
Decision: Is generator voltage Phase A <250 or >310 for ≥ 1 second?
Decision: Is generator voltage Phase B <250 or >310 for ≥ 1 second?
Decision: Is generator voltage Phase C <250 or >310 for ≥ 1 second?
Decision: Is generator amps Phase A <0 or >350 for ≥ 1 second?
Decision: Is generator amps Phase B <0 or >350 for ≥ 1 second?
Decision: Is generator amps Phase C <0 or >350 for ≥ 1 second?
Decision: Is generator frequency <59.5 or >60.5 for ≥ 1 second?

End Engine Diagnostic test function

Process: Call Absorption Chiller Modulation function

Begin Abs Chiller Modulation function (every 15 minutes)

Decision: Is cogeneration supply water temperature <32°F or >210°F for ≥ 10 seconds?
Decision: Is cogeneration supply water temperature >220°F for ≥ 10 seconds?
Decision: Is cogeneration return water temperature >200°F for ≥ 10 seconds?
Decision: Is cogeneration return water temperature >210°F for ≥ 10 seconds?
Decision: Is jacket water >165°F?
Decision: Is total of condenser water pump amps >1.0?
Decision: Is total of chilled water pump amps >1.0?
Decision: Is absorption chiller enabled flag true?
Decision: Is chiller capacity control valve open >10%?
Decision: Is cogeneration water return temperature >167°F?
Process: Determine co-modulation quantity.
Decision: Is condenser water return temperature >82°F?
Process: Determine cdw-modulation quantity.
Decision: Is cooling tower water bypass valve 100% closed?
Process: Subtract chilled water supply temperature from chilled water return temperature; store the result in chilled water temperature difference.
Decision: Is chilled water temperature difference <8°F?
Process: Determine cw-modulation quantity.

End Abs Chiller Modulation function

Begin Engine Throttle function

Process: Call Engine Throttle function (every 2 minutes)
Process: Get current kilowatt output for ICE-n
Process: Get four most current values (past hour) from Net Building Load array
Process: Estimate Next Net Building Load value
Decision: Is Net Building Load or Next Net Building Load ≤ Throttle-Down Threshold?

```
      Decision: Is Net Building Load or Next Net Building Load ≥ GeneratorMax kilowatts?
      Decision: Is current ICE-n kilowatts < Net Building Load/105% (accounting for design margin)?
  End Engine Throttle function

  Begin ThrottleUp function
  Process: Throttle up to within 5% of Net Building Load (but stop at ICE max kilowatts)
  End ThrottleUp function

  Begin ThrottleDown function
  Process: Throttle down to within 5% of Net Building Load
  End ThrottleDown function

  Begin DER Dispatch function
      Decision: Are >1 ICEs running?
  Process: Calculate value of thermal credit = Get ton-hours delivered; multiply by price/ton-hour
  Process: Calculate cost to operate ICE-n
  Process: Calculate value of electric generation
  Process: Calculate net value of CHP
  Process: Compare against net value of PV generation
  Process: Choose the greater value
      Decision: Is value of ICE generation >PV generation?
      Yes: Trip PV
      No: Stop ICE
  End DER Dispatch function
End Main
```

2.5 Conclusions

Optimal dispatch in the DEIS system envisioned in this report is a dynamic process involving continuous assessment of system profitability. There are many factors that affect profitability including the price of gas, the cost of O&M, the 5% design margin, the value of CHP thermal dispatch, the applicable tariff, the gross building load, the net building load, the strength of the solar day, and the engine heat rate curve. Of these, gas price, O&M, design margin, applicable tariff, the net building load, and engine heat rate are all captured in an important set of numbers called the Throttle-Down Thresholds. These thresholds are the limits of generating capacity kilowatts that can be met profitably, beneath which operation is unprofitable. The thresholds are recalculated hourly based on fluctuating gas prices and the other factors noted above. The price of gas is critical to optimal dispatch. (See Figure 2.4.5-4.) The value of the thermal credit can justify running an ICE below the Throttle-Down Threshold, particularly if the building cooling load ranges 80–200 tons, the very bottom of the efficiency curve for the 300-ton chiller. The thermal credit can be worth up to 75% of the total cost to run the chillers (Table 2.4.4-1). Dispatch in the daytime during weekdays is usually much simpler than off-peak because the PV follows the building load shape very closely (Figure 2.2.1-2). Running PV on weekends and holidays can be problematic because the PV often reduces net building load below the ICE Throttle-Down Threshold (see Figure 2.3.2-2). When this happens, a dispatch decision must be made to trip the PV or the ICE (see sections 2.4.5.2 and 2.4.6). The decision cannot be foregone because it depends on a number of factors, including gas price, value of thermal credit, and solar output, which change hourly. It is possible that the system will make a mistake and trip the wrong generator source because the dispatch decision is made partly on a prediction of a trend. With the DEIS, the system can pick up the correctness or incorrectness of the decision as it becomes incorrect and can often rectify it quickly, depending on generator re-start times.

Task 3: Develop Codes and Modules for Optimal Dispatch Algorithms

3.1 Introduction

The purpose of this task is to develop optimized codes for the algorithms developed in Task 2 that enable the economic dispatch of RE's fleet of systems. This task will present an abstraction of the modules and code of RE's DEIS. The flowchart (see Section 2.4.6) and algorithms of the dispatch sequence (see Section 2.4.7) described in Task 2 will be described more fully here and will be improved where analysis leads to an improvement of the Task 2 model. The functions will be made more modular.[20] The code that could support the functionality of the algorithms is included in the dispatch sequence (Section 2.4.7). The pseudo-code is written with C++ as the target implementation language. Both object and procedural techniques (afforded by C++ and C, respectively) will be used. The system will not be described from a pure object-oriented analysis because the procedural point of view is more useful for a first-things-first analysis.

It is important to distinguish the abstraction presented in this report from the implementation in the field. The field implementation is proprietary and ad hoc, and both of these qualities make it a poor choice for system description. The design in this report should not be mistaken for a blueprint for a software team. The purpose of this report is to provide a detailed analysis from a procedural and object-oriented perspective of the functioning of the DEIS. Many details of an actual functioning system are left out.[21] The analytical tools used are meant to clarify and describe the real working system.

Procedural analysis will include a full listing of the dispatch sequence, isolation and description of algorithms, and description of logic code (i.e., the functions and program logic that determine the path taken through the sequence). Procedural analysis gives the sequence of operations and the actions that must be taken during the sequence.

Terms Used in Procedural Analysis

An algorithm is a set of rules that specify the order and kind of arithmetic operations that are used on a specified set of data.[22] In the dispatch sequence of Task 2, they are limited to inputs/outputs, decisions, processes, and returns of function value. The dispatch sequence is the full listing of algorithms. Functions are made up of a related set of algorithms that together perform a required task, such as starting an engine. Most functions are called from within other functions. Exceptions to this are functions called by the normal running of the program [the main() function, for example]. In Task 2, we use the word *function* when naming functions. This task, however, and the rest of the report, uses the more correct function designation: the name of

[20] "Modular architecture … refers to the design of any system composed of separate components that can be connected together. The beauty of modular architecture is that you can replace or add any one component (module) without affecting the rest of the system. The opposite of a modular architecture is an integrated architecture, in which no clear divisions exist between components." From the Lycos Webopedia at http://webopedia.lycos.com/.

[21] For example, there is no definition of objects or their data members or any explanation of object interface. For this reason, the functions sometimes use a piece of data without explaining how they got it. A programmer would have to specify which object members could access which other object members and which could not.

[22] This definition is from the National Oceanic and Atmospheric Association's Met Ed Web site: http://meted.ucar.edu/export/asos/ALGO1.HTML

the function followed by open and closed parentheses. When actually calling a function in code, the parentheses will contain any data the function needs to do its job. These data are called parameters or arguments, and each function can have 0 to n of them. An actual function call looks like this: FunctionName(parameter1, parameter2, parameter3…). When functions have completed their task, they return program control to the function that called them, and they may return a value. The return value is often a "0," indicating that nothing is wrong, or a "-1," indicating that something went awry. With few exceptions, parameters are not passed to the functions; instead, they get the data they need from objects common to the calling module and the called module. Functions will be given legal function names, such as ICEStart() and DERDispatch(), using variable and naming conventions common in object-oriented programming. All functions will run within the standard C/C++ "function" called main().

3.2 Procedural Analysis

3.2.1 Flowchart Revision

In Task 2, the flowchart in Figure 2.4.6-1 was proposed to describe the working system. Analysis carried out in modularizing the DEIS logic led to a reorganization of the program design to become more compact and efficient. It is not necessary, for example, to have a separate "Startup" function, when that could be better handled by main(). Then all functions could be called within main(). It would also give DERDispatch(), once it is called by main(), the job of calling all other functions based on messages it receives. This flexibility allows DERDispatch() to change operation based on analysis of the constantly changing situation. The revised flowchart logic also includes stop functions for ICE, PV, and the absorption chiller.

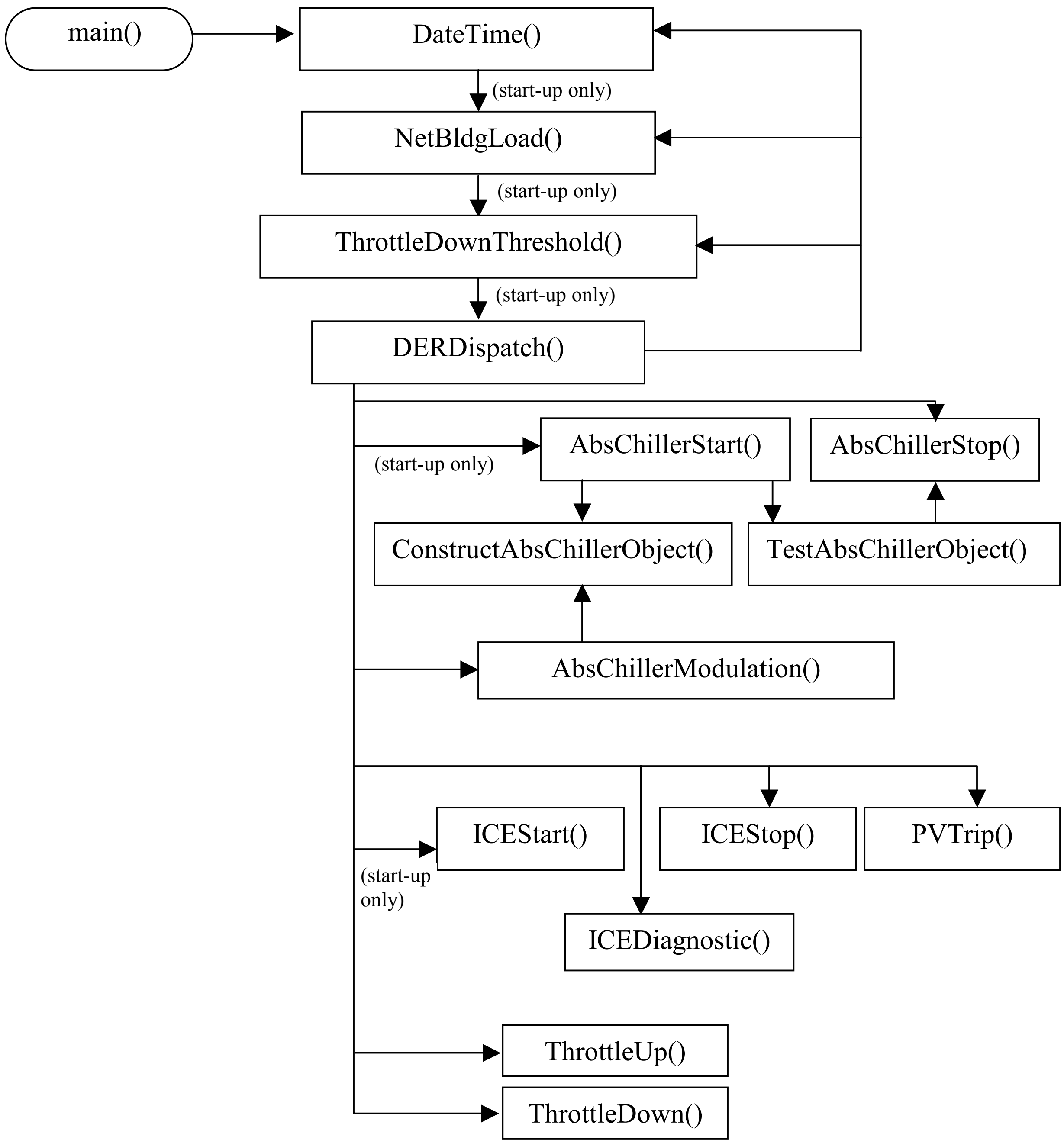


Figure 3.2.1-1: The DEIS revised flowchart

In the revised procedural design in Figure 3.2.1-1, main() starts the program and runs DateTime(), NetBldgLoad(), ThrottleDownThreshold(), and DERDispatch(). When DERDispatch() first runs, it checks for the "OK to run" signal from the building. Then it makes sure this is a valid time to operate. If so, it runs the AbsChillerStart() function, which in turn calls ConstructAbsChillerObject(), which gets all temperatures and valve openings of the absorption chiller system. Then AbsChillerStart() calls TestAbsChillerObject(), which runs diagnostics on the system. Once these have completed and returned to DERDispatch(), the latter checks whether the current building load is big enough to run the first IC engine (ICE-1). If so, ICEStart() runs and starts up ICE-1. If this happens successfully, DERDispatch goes into continuous operation mode.

It launches AbsChillerModulation(), a separate program thread, which gathers supply and return temperatures and valve settings from each of the three system absorption chiller loops: the cogeneration water loop, the condenser water loop, and the chilled water loop. This is accomplished in the ConstructAbsChillerObject() function.

Meanwhile, DERDispatch(), in continuous operation mode, runs the system according to the timer. Every 1 minute, DERDispatch() does the following:

- Calls NetBldgLoad() to update load fluctuation
- Gets PV output
- Gets ICE electric and thermal output
- Calculates the value of all these
- Throttles up if load has risen
- Throttles down if load has decreased
- Starts ICE-2 if net building load can handle it
- Stops ICE-2 if net building load cannot handle it
- If operation is below Throttle-Down Threshold, figures out if thermal credit plus loss is greater than PV output. If so, trips PV; if not, stops the marginal ICE.

Every 60 minutes, DERDispatch() does the following:

- Calls DateTime()
- Calls ThrottleDownThreshold() to refresh these values.

Under normal conditions, DERDispatch continuously calculates thermal credit and rate tariffs and operates ICEThrottle() to maximize system profitability.

DERDispatch() is ultimately responsible for handling all system exceptions either automatically or by alarming for manual decision by RE personnel. AbsChillerModulation() is actually a very low-level part of the DEIS and is handled by the chiller controller. If it has a problem, though, it must notify DERDispatch() to implement Alarm() or Stop() conditions.

3.2.2 Hierarchy of Functions

The modules of the DEIS are arranged hierarchically with main() on the top tier, DERDispatch() on the second tier, and all other programs on the third tier. Several forth-tier modules [such as ThermalCredit()] are shown in the listing but are not discussed here. They are modularized simply to gain the benefit of modular architecture. DateTime(), NetBldgLoad(), and ThrottleDownThreshold() are second-tier programs at start-up [because they are called by main()] but not at any other time [because they are always called subsequently by DERDispatch()].

Table 3.2.2-1: Hierarchy of Functions and Their Triggering Events

Notes	Function	Level of Hierarchy	Called at Start-Up By	Called During Continuous Operation By	Event Triggering This Function During Continuous Operation
1	main()	1	n/a	n/a	Continuous operation
2	DateTime()	2,3	main()	DERDispatch()	60-minute interval timer
3	NetBldgLoad()	2,3	main()	DERDispatch()	1-minute interval timer
4	ThrottleDownThreshold()	2,3	main()	DERDispatch()	60-minute interval timer
5	DERDispatch()	2	main()	n/a	Continuous operation
7	AbsChillerStop()	3	n/a	DERDispatch()	Message from DERDispatch()
8	AbsChillerModulation()	3	DERDispatch()	n/a	Continuous operation
9	ConstructAbsChillerObject()	3	AbsChillerStart()	DERDispatch()	1-minute interval timer
10	ICEStart()	3	DERDispatch()	DERDispatch()	Message from DERDispatch()
7	ICEStop()	3	n/a	DERDispatch()	Message from DERDispatch()
7	PVTrip()	3	n/a	DERDispatch()	Message from DERDispatch()
11	ICEDiagnostic()	3	DERDispatch()	DERDispatch()	Message from DERDispatch()
12	ThrottleUp()	3	DERDispatch()	DERDispatch()	Message from DERDispatch()
12	ThrottleDown()	3	DERDispatch()	DERDispatch()	Message from DERDispatch()

Notes

1. main() starts all other functions and operates continuously while the DEIS is on.
2. DateTime() is Level 2 at start-up because it is called by main(); after start-up, it is run continuously by DERDispatch() so that it is Level 3 on the function hierarchy.
3. NetBldgLoad() is the same as DateTime() except it is run by DERDispatch() on a 1-minute interval.
4. ThrottleDownThreshold() is like DateTime(), both in dispatch and timing interval.
5. DERDispatch() is called by main() at start-up but is run thereafter as a separate thread. DERDispatch() contains internal member functions including AbsChillerStart() and TestAbsChillerObject().
6. AbsChillerStart() only runs at start-up; continuous operation is handled by AbsChillerModulation().
7. AbsChillerStop(), ICEStop(), and PVTrip() are called at system shutdown by DERDispatch().
8. AbsChillerModulation() is called at start-up by AbsChillerStart() and then runs as a separate thread. This function controls thermal dispatch; it is the only function besides its children not controlled by DERDispatch().
9. ConstructAbsChillerObject() is called each minute to report return and supply temperatures and modulate valves and fans on the cogeneration loop, cooling tower loop, and chilled water loop so that each stays within required operating temperatures.
10. ICEStart() is run at start-up for ICE-1 and once for each additional ICE when building load is increasing.
11. ICEDiagnostic() is called by DERDispatch() during start-up, on alarm, at AbsChillerStop(), and at ICEStop().
12. ThrottleUp() and ThrottleDown() are operated by DERDispatch() based on ICE identification and kilowatt output.

3.2.3 Function Parameters and Return Values

Each of the functions defined have input requirements, function parameters, and output requirements that are contained in a data item called a return value. In C and C++, only one return value is allowed per function. By returning an object (or a pointer or reference to an object), it is possible to have the return be of any complexity desired. The following figure shows the parameters and return values of the DEIS functions.

Table 3.2.3-1: Function Arguments and Return Values

Notes	Function	Arguments	Return Value(s)
1	main()	command line	0 = normal; -1 = error
2	DateTime()	none	DateTimeObject
3	NetBldgLoad()	none	NetBldgLoadObject, updated
4	ThrottleDownThreshold()	DateTimeObject	ThrottleDownObject
5,6	DERDispatch()	ThrottleDownObject, DateTimeObject, NetBldgLoad[]	0 = normal; -1 = error
6	AbsChillerStop()	none	0 = normal; -1 = error
6,9	AbsChillerModulation()	ICEStatusFlag (0 = Start-up, 1= Run, 2 = Shutdown)	0 = normal; -1= error
7	ConstructAbsChillerObject()	none	AbsChillerObject
6	ICEStart()	ICE-id	0=normal; -1=error
6	ICEStop()	ICE-id	0=normal; -1=error
6	PVTrip()	none	0=normal; -1=error
6	ICEDiagnostic()	ICEStatusFlag (0 = Start-up, 1 = Run, 2 = Shutdown)	0 = normal; -1 = error
8	ThrottleUp()	ICE-id, ICE-kW	ICE-kW; -1 = error
8	ThrottleDown()	ICE-id, ICE-kW	ICE-kW; -1 = error

Notes

1. main() can be run from the command line, so it takes (unspecified) command-line arguments.
2. The DateTimeObject is a data structure with Year, Month, Day, Hour, and Second variables in it; it also has ApplicableTariff, TariffCost, and TariffEndDateTime.
3. NetBldgLoad() contains an object NetBldgLoadObject that is a database of values for gross building load, PV generation, and net building load; the function gathers the current values and puts them into the database.
4. ThrottleDownThreshold() returns a ThrottleDownObject containing a threshold member, an integer minimum wattage at which the ICE can run under current rate tariff and other conditions, and a gas price float value with the current gas price.
5. DERDispatch() takes the return values of each of the three previous functions as arguments. DERDispatch() contains internal member functions including AbsChillerStart() and TestAbsChillerObject().
6. Like main(), DERDispatch(), AbsChillerStop(), AbsChillerModulation(), ICEStart(), ICEStop, and ICEDiagnostic() return 0 or -1.

7. ConstructAbsChillerObject() has no arguments; it returns an object that contains all data necessary for AbsChillerModulation() to regulate supply and return temperatures of the cogeneration, cooling tower, and chilled water loops.
8. ThrottleUp() and Throttle() take an ICE-id that tells which engine to throttle, and ICE-kW integer that tells how much to throttle.
9. AbsChillerModulation() receives ICEStatusFlag (set = 0) first from AbsChillerStart, then from DERDispatch after the ICE starts (set = 1), and then from ICEStop (set = 2). During continuous operation, it calls ConstructAbsChillerObject() to get updated information on supply and return temperatures so that it can regulate fan speed and valve settings to control temperatures of the cogeneration, cooling tower, and chilled water loops.

Given these functions, it is possible to revise the algorithms that make up each function in a revised dispatch sequence listing.

3.2.4 Code for Dispatch Sequence

The following is pseudo-code, not source code (i.e., it is not written in a way that a source code compiler can understand). Rather, it is written in a manner similar to C++ but in a way that a human reader who is not a programmer can read and understand. Wherever possible, the explanations have been made in C++ style "comments" (preceded by "//") to make the code closer to real source code. This approach is taken to give a sharp outline to how the DEIS source code would work without getting bogged down in implementation details that would not add to an understanding of what the program was doing. The line numbers are for reference only. They are *not* part of the code.

Description:

- Line 1: The main program starts [note that the program is really a function called main()].
- Line 3: The program calls the DateTime() function; DateTime() checks the clock to find out what day and time it is.
- Line 5: The program calls the NetBldgLoad() function; this function checks to find out the size in kilowatts of the unserved building load.
- Line 7: The program calls the ThrottleDownThreshold() function; this function figures out, given the date and time, at what minimum kilowatt output the engines can operate profitably.
- Line 10: The program calls DERDispatch(), the function that will operate the DEIS continuously until it is shut off.
- Lines 14–40: The function DateTime() is defined. It asks the Main Meter what time and date it is. The function loads the information into a DateTimeObject, which it returns to the main program.
- Lines 42–49: The function NetBldgLoad() is defined. It asks the Main Meter what the building load is in kilowatts. It returns the result to the main program.
- Lines 51–68: The function ThrottleDownThreshold() is defined; it figures out how low in kilowatts each engine can operate profitably.
- Lines 70–267: The function DERDispatch() is defined. The first time the program runs, the system goes through a start-up sequence by checking for a signal from the building that it is OK to run and checking the time and date to make sure there are no restrictions against running. If these check OK, the system begins start-up:

1. It starts the absorption chiller start-up sequence (function defined in lines 89–99).
2. The conditions of the thermal recovery system are tested and the results recorded in a data object (AbsChillerObject).
3. The AbsChillerObject is tested (lines 101–139) for alarm conditions or other operational problems.
4. A function called LoadOkay() (lines 142–152) makes sure that there is sufficient load to operate the generator. If there is not, the system waits 1 minute; if there is, the program continues (lines 153–161).
5. The program begins engine start-up, running diagnostic tests and recording the results in a data object (lines 163–171). If there are no errors, the program goes into continuous operation; otherwise, an alarm is sent.

Continuous operation begins (Line 173) with the absorption chiller beginning its self-modulation sequence (lines 176–179). After setting some initial variables, the program begins a series of tasks that are repeated every minute (lines 191–257), including:

1. Checking building load
2. Calculating the value of chilled water delivery, the thermal credit
3. Figuring out whether the system should throttle up, throttle down, or stay where it is
4. Calculating the value of the solar photovoltaic generation
5. Starting an additional engine (or engines) if the load is sufficient, or if load is insufficient for generation, making a decision, based on economics, whether to shut off the engine (and lose the thermal credit) or trip the PV.

At the end of this sequence of 1-minute tasks, the program checks whether it is at the top of the hour. If so, hourly tasks are performed (lines 259–265), including getting the date and time (to see whether the utility tariff has changed) and updating the Throttle-Down Threshold. The program then loops back to the beginning of its continuous operation sequence.

- Lines 271–316: The function ConstructAbsChillerObject() is defined. It collects temperatures from the supply and return lines of the cogeneration, cooling tower, and building supply systems. It also makes sure that pumps are operating by taking a reading of their amperage and finds out whether the building needs more or less chilled water. It stores these readings in program variables.
- Lines 319–341: The function AbsChillerModulation() is defined. It uses the temperature information collected in the previous function to decide which valves to open or close. If the building wants more chilled water, it lets more hot cogeneration water into the absorption chiller; if the building wants less chilled water, it lets less hot cogeneration water into the absorption chiller. If the cogeneration return water is too hot to cool the engines properly, the program opens the valve to the balance radiators and turns up the variable frequency drive on the radiators to cool the water more quickly.
- Lines 344–353: The function ICEStart() is defined; it starts up the engine. If there is a problem, it sends an alarm and returns an error code to the main program. If the engine starts normally, the function returns a 0, meaning everything is OK.

- Lines 355–420: The function ICEDiagnostic() is defined; it is a complete set of instructions for the engine self-test. It stops the engine if there is a serious problem in any of the diagnostics and sends an alarm message.
- Lines 424–430: The function ThrottleUp() is defined. It takes input for which engine is to be throttled up and the target kilowatt to which it should be throttled.
- Lines 432–438: The function ThrottleDown() is defined; it works the same way as ThrottleUp(), only it throttles the specified engine down to the target kilowatt setting. ThrottleUp() and ThrottleDown() are the load-following capability of the DEIS.
- Line 439: the main() program ends.

Code:

```
1  main()  {                 // begin main()
2                            // construct objects, declare variables (not shown)
3  DateTime();               // call DateTime()
4
5  NetBldgLoad(NetBldgLoadObject);  // call NetBldgLoad() and pass the NetBldgLoadObject
6
7  ThrottleDownThreshold(DateTimeObject); // call ThrottleDownThreshold() and pass the
8                                         // DateTimeObject
9
10 DERDispatch(ThrottleDownObject, DateTimeObject, NetBldgLoadObject);
11                 // call DERDispatch() and pass the ThrottleDownObject, DateTimeObject, and
12                 // NetBldgLoadObject
13
14     DateTime()  {          // begin DateTime()
15         Get PML Generator Meter current date and time;
16         // Now use the info from PML to construct DateTimeObject
17                                             DateTimeObject.year = Year;          //
18                                          assign local variable "Year" to the
19                                                                                  //
20                                          DateTimeObject data member "year"
21         DateTimeObject.month = Month;// same as above
22         DateTimeObject.day = Day;
23         DatetimeObject.hour = Hour;
24         DateTimeObject.minute = Minute;
25         DateTimeObject.second = Second;
26         // create an integer "time" from year, month, day, hour, minute, second
27         DateTimeObject.time = integerRepresentationOfTime() //not defined
28         DateTimeObject.dayofweek = DayofWeek;
29         Process: Determine if it is a Sunday or Holiday = 0, Saturday = 1 or a
30         NonHolidayWeekday = 2 and assign result to OccupancyValue;
31         DateTimeObject.occupancyvalue = OccupancyValue; // 0, 1, or 2
32         Process: Determine ApplicableElectricRateTariff
33         DateTimeObject.tariff = ApplicableElectricRateTariff;
34         // Get internal constants for beginning and ending time of use
35         DateTimeObject.begin = ScheduledTOUBeginTime;
```

```
            DateTimeObject.end = ScheduledTOUEndTime;


            return DateTimeObject;
        }               // end DateTime()

        NetBldgLoad() {   // begin NetBldgLoad()
            NetBldgLoadObject.currentgross = Get gross building load from PML Generator
            Meter;
            NetBldgLoadObject.currentPV = Get PV generation output from PML Generator
            Meter;
            NetBldgLoadObject.currentnet = .currentgross – .currentPV;
            return NetBldgLoadObject;
        }               // end  NetBldgLoad

        ThrottleDownThreshold(DateTimeObject)  {          // begin ThrottleDownThreshold()
            Output: Get current gas price
            Input: Current gas price
            Process: Using internal dataset for ICE heat-rate curve, determine cost per kWh to
            operate at 1-kW increments from 110% to 10% of kW output capacity.
                Derive fuel consumption in scf/m by multiplying the heat rate scf/m per
                        Btu/kWh constant;
                Derive CostPerHour by multiplying scf/m by GasPrice ($/scf) by 60;
                Derive CostToOperate (per kWh) at current kWOutput by dividing kWOutput by
                        CostPerHour;
                Compare CostToOperate to CurrentRateTariff at each kWOutput number, starting
                        at the 10% (20 kW); when CurrentRateTariff >kWOutput,
                        ThrottleDownObject.threshold = (kWOutput * 1.05);
                                // assign kWOutput, plus a 5% design margin, as the threshold
                        ThrottleDownObject.gasprice = GasPrice;
                                // assign the gas price to the return object
            return ThrottleDownObject;
            }           // end ThrottleDownThreshold()

       DERDispatch(ThrottleDownObject, DateTimeObject, NetBldgLoadObject)   {
                        // begin DERDispatch(), which will run until system shuts off

        StartUp flag = 1;       // set local variable flag to run start-up sequence
        If StartUp = 1 {        // begin start-up
                Output: Request OK to run generator flag status from host building control
                Input: Receive OK to run generator flag status from host building control
             Decision: Is OK to run generator flag status true?
                        Yes: Continue
                        No: Alarm, wait and try again in 1 minute.
                // make sure this is a valid time of use
                if(DateTimeObject.time >DateTimeObject.begin and <DateTimeObject.end)
```

```
                continue;
            else
                wait (DateTimeObject.begin – DateTimeObject.time); }// wait until it is OK
            ICEStatusFlag = 0;                          // ICE is in start-up mode
        AbsChillerStartValue = AbsChillerStart(ICEStatusFlag);  // run absorption chiller
                // start up internal function and assign the result to a flag

        AbsChillerStart(ICEStatusFlag)  {
        SequenceNumber = 1;  // local variable to note place in absorption chiller op sequence
        Control output: Enable building condenser water pump and cooling tower fan control
        Control output: Start Cogeneration Supply Water pump
        ConstructAbsChillerObject();
        TestAbsChillerObject(SequenceNumber);   // call an internal diagnostic function
        Control output: Start chiller, condenser pump, and chilled water pump
        SequenceNumber = 2;
        ConstructAbsChillerObject();
        TestAbsChillerObject(SequenceNumber);
        }               // end AbsChillerStart()

        TestAbsChillerObject(SequenceNumber)  {                    // begin function
                If (SequenceNumber = 1) {

        // AbsChillerObject is accessible (public) to this function, so it does not have to be
        // passed as a parameter.

        if(AbsChillerObject.CogenSupplyPumpAmps ≤ 1.0) { // if pump is not on
                Alarm();
                Return –1; }
         if(AbsChillerObject.CogenSupplyTemp <35°F
               || >210° F for ≥ 10 seconds)   {  // if cogen supply is too hot or cold
               Alarm ();
               Return –1;  }
        if(AbsChillerObject.CogenSupplyTemp >220°F for ≥ 10 seconds)  {
                                          // if cogen supply is too hot and temp is not decreasing
                ICEStop();
                AbsChillerStop();
                Return –1; }
         if(AbsChillerObject.CogenReturnTemp >200°F for ≥ 10 seconds)  {
                                                            // if cogen return is hotter than usual
                Alarm();
               Return –1;   }
         if(AbsChillerObject.CogenReturnTemp >210°F for ≥ 10 seconds)  {
            ICEStop();
                AbsChillerStop();
                Return –1;  }
        }     // end if statement
```

```
    if(SequenceNumber = 2) {    // begin second sequence
        if(AbsChillerObject.CondenserWaterPumpAmps ≤ 1.0)   {  // if pump is not working
                    Alarm();
        if(AbsChillerObject.ChilledWaterPumpAmps ≤ 1.0)
                Alarm();
        if(AbsChillerObject.AbsChillerEnabledFlag = FALSE )
                    Alarm();
        if(AbsChillerObject.ChillerCapacityControlValvePct <10%)
                Alarm();
      }  // end if statement
    } // end TestAbsChillerObject()


        Process: Verify OK to run flag status
        Output: Get number of ICEs running and kW output
        Input: PML Generator Meter, # of ICEs, and kW output
        LoadOkayFlag = LoadOkay(); //function to check if load is big enough
            LoadOkay()  {  // definition of function
                if(kW output of ICEs from generation capacity + Throttle-Down Threshold
            <total ICE generator capacity )   // make sure load can handle ICE
                            return 1;
                    else
                            return 0;
            }  // end LoadOkay()
            if(LoadOkayFlag)       // if LoadOkay returned true
                    ICEStartValue = ICEStart(ThrottleDownObject.threshold)
                                                    // start up ICE,
                                                    // assign return to a local variable
            }
         else {
                Wait (1 minute);
                LoadOkayFlag=LoadOkay();
            }

         if(ICEStartValue = 0)    //  If no alarms
                ICEDiagnostic(ICEStatusFlag);  //  call engine diagnostic test
         else Alarm();                         // or else notify manual dispatch of the error

            if AbsChillerStartValue = 0 and ICEStartValue = 0  { // if there are no errors from
                                                                  // ICE or abs chiller
                    StartUp = 0;              // end start-up sequence by setting flag to 0
            }
            else Alarm();                     // notify manual dispatch of the error

  // Go into continuous operation sequence
```

```
                ICEStatusFlag = 1;              // engine is running
                AbsChillerModulationValue = AbsChillerModulation( ICEStatusFlag );
                                                // begin absorption chiller self-modulation process
                if(AbsChillerModulationValue = -1)  // if there is an error
                        Alarm();                        // send an alarm to manual dispatch

        int Timer = StartTimer();  //start a timer sequencer function (not defined here)
        // declare a constant margin below building net kW to maintain, call it Margin
        const int Margin = .05  // 5% design margin example
        const int OneICEMax = 220; // max kW output of one engine
        const int TotalICEMax = 2 * OneICEMax; //
        const int TwoICEMin = OneICEMax + ThrottleDownObject.threshold
        // function to stop DERDispatch
         bool StopOperation = CheckForStopOperationMessage();
        while( StopOperation = FALSE )  {  // begin DERDispatch() continuous operation

            if(Timer % 60seconds = 0)  {       // do these tasks every 1 minute

            NetBldgLoad();
            // call NetBldgLoad()

            // Calculate Thermal Credit as value to Host Customer
            AbsChillerOutput = GetAbsChillerOutput();
            /* function (not defined here) to get absorption chiller ton-hours – gets ton-hours data
            for the previous period from the Btu meter. */
            ThermalCredit ( AbsChillerOutput )  {
                    return AbsChillerOutput * PricePerTonHour;
            }

            // figure out whether to throttle up or down
            ICEOutputkW = GetCurrentICEOutput();
            // function gets engine output from PML Generator Meter
            PVOutputkW = GetCurrentPVOutput();
            // function gets PV output from PML Generator Meter

            ValueOfPV(DateTimeObject.tariff) {
            Return  DateTimeObject.tariff * PVOutputkW;
            }

            // throttle up or down if required
            if(this NetBldgLoad == last NetBldgLoad)  { // if there’s no change,
                        continue; }  // do nothing;
            else  {  // do something
                        if (this NetBldgLoad >last NetBldgLoad)  { // if the load has gone up,
                                ThrottleUp(this NetBldgLoad – last NetBldgLoad);
```

```
 // throttle up by amount of change
        if (this NetBldgLoad < last NetBldgLoad )  { // if the load has gone down
            ThrottleDown( last NetBldgLoad – this NetBldgLoad )
                // throttle down by amount of change
}
// exceptions:
if (ICE-2 is off and this NetBldgLoad >OneICEMax but <TwoICEMin)then do
nothing;

// if building load can handle it, start ICE-2
else
  if (ICE-2 is off and this NetBldgLoad > TwoICEMin)
      ICEStart(ICE-2);

// if the load is below the threshold for ICE-1 or ICE-2
else
  if (NetBldgLoad <ThrottleDownObject.threshold && PVOutputkW ≤
(ThrottleDownObject.threshold – NetBldgLoad)   )  {
        // and PV is not the cause
        // then figure out if ThermalCredit makes operation worth it
        if (ThermalCredit >loss from running below Throttle-Down Threshold)
          continue;  // then do nothing
        else
      if[(ThermalCredit + loss) <0]
     // shut off the engine that is operating unprofitably
      ICEStop( ICE-n );
    }
    else { if [PVOutputkW >(ThrottleDownObject.threshold – NetBldgLoad)]  {
        // if PV is the cause
        // then figure out if PV should be tripped
        if(ValueOfPV >ThermalCredit)
            ICEStop( ICE-n );
            // shut off the engine that is operating unprofitably
        else { if (ValueOfPV <(ThermalCredit – loss from operating below
threshold)
            PVTrip();  // trip the inverter to shut off PV
      }
    }

if(Timer % 60minutes = 0)  {       // do these tasks every hour

     // get updated date and time
     DateTime();  values
     // get ThrottleDownThreshold() values
     ThrottleDownThreshold(DateTimeObject);
} // end if
```

```
    } // end while loop
  } // end DERDispatch



    ConstructAbsChillerObject()  {                    // begin function

        // assign system monitored results to object data members
        Output: Request Cogeneration Supply Water pump amps
        AbsChillerObject.CogenSupplyPumpAmps = Cogeneration Supply Water pump
  amps;
        Output: Request Condenser water pump amps
        AbsChillerObject.CondenserPumpAmps = Return Condenser water pump amps;
        Output: Request Chilled water pump amps
        AbsChillerObject.ChilledWaterPumpAmps = Chilled water pump amps;
        Output: Request Absorption Chiller Enabled flag status
        AbsChillerObject.AbsChillerEnabledFlag = Absorption Chiller Enabled flag status;
        Output: Request building chilled water demand.
        AbsChillerObject.BldgChilledWaterDemand = Building chilled water demand;
        Output: Request chiller capacity control valve open percentage
        AbsChillerObject.ChillerCapacityControlValvePct = Chiller capacity control valve
        open percentage
        AbsChillerObject.CoolingTowerBypassValvePct = Cooling tower bypass valve open
        percentage

        Output: Request Cogeneration Supply Water Temperature
        AbsChillerObject.CogenSupplyTemp = Cogeneration Supply Water Temperature;
        Output: Request Cogeneration Return Water Temperature
        AbsChillerObject.CogenReturnTemp = Cogeneration Return Water Temperature;
        Output: Request Condenser Water return temperature
        AbsChillerObject.CondenserWaterReturnTemp = Condenser Water return
        temperature;
        Output: Request Condenser Water supply temperature
        AbsChillerObject.CondenserWaterSupplyTemp = Condenser Water return
        temperature;


        Output: Request Chilled water return temperature
        AbsChillerObject.ChilledWaterReturnTemp = Chilled water return temperature;
        Output: Request Chilled water supply temperature
        AbsChillerObject.ChilledWaterSupplyTemp = Chilled water supply temperature;

        AbsChillerObject.ChilledWaterTempDifference =
        AbsChillerObject.ChilledWaterReturn – AbsChillerObject.ChilledWaterSupply;

            Output: Request MMBtu of cooling delivered to user
```

```
            AbsChillerObject.DeliveredCooling = MMBtu of cooling delivered to user;

            Return AbsChillerObject;

    }  // end ConstructAbsChillerObject()


AbsChillerModulation (ICEStatusFlag)  {  // begin AbsChillerModulation()

        // declare minimum and maximum return and supply temps for cogen, chilled water,
        // and condenser water loops
        // declare acceptable ranges from the min and max

        if(Timer % 60seconds = 0)  {       // do these tasks every 1 minute

            ConstructAbsChillerObject();
            if(AbsChillerObject.CogenSupply water >maximum °F   {
                        Control Output: Open Balance Radiator valve;
                        Control Output: Adjust VFD fan speed to lower cogeneration
            water to minimum;
                        }
            if(AbsChillerObject.CondenserWaterReturnTemp >maximum °F  {
                        Control Output: Close cooling tower water bypass valve;
             if(AbsChillerObject.CoolingTowerBypassValvePct == 100%)
                              Control output: Increase VFD to reduce supply water temp;
            }
                if(AbsChillerObject.ChilledWaterReturnTemp <minimum°F )
                Control output: Open Absorption Chiller bypass;
          } // end Timer loop
    }  // end AbsChillerModulation()


ICEStart()  {      // Begin ICEStart()
         Control Output: Start ICE
         if (ICE is running), continue
        else Alarm();
        Output: Request ICE-1 Kilowatt output from PM Generator Meter
        Input: Return ICE-1 Kilowatt output from PM Generator Meter
        if(ICE-1 Kilowatt output >20 kW),
              Return 0;               // Return OK
              else Return –1;       // Return error
    }  // end ICEStart()

        ICEDiagnostic(ICEStatusFlag)   {           // begin ICEDiagnostic
            Output: Request current oil pressure
            Input: Return current oil pressure
```

```
if(oil pressure <10% of normal operating pressure for more than 1 second) {
        ICEStop();
        return –1;
      }
      if(oil pressure >110 psi for 10 seconds)
              Alarm();
 Output: Request Combustion air temp
 Input: Return Combustion air temp
 if(Combustion air temp >130°F for ≥10 seconds )  {
        ICEStop();
        return –1;
      }
 Output: Request Kilowatt output
 Input: Return Kilowatt output
 if(Kilowatt total output <160 or >220 for ≥ 10 seconds)
              Alarm();
 if(Kilowatt total output <140 for ≥ 10 seconds)  {
        ICEStop();
 return –1;
      }
 Output: Request Generator Voltage Phase A
 Input: Return Generator Voltage Phase A
 Output: Request Generator Voltage Phase B
 Input: Return Generator Voltage Phase B
 Output: Request Generator Voltage Phase C
 Input: Return Generator Voltage Phase C
 Output: Request Generator Amps Phase A
 Input: Return Generator Amps Phase A
 Output: Request Generator Amps Phase B
 Input: Return Generator Amps Phase B
 Output: Request Generator Amps Phase C
 Input: Return Generator Amps Phase C
 if(Generator Voltage Phase A <250 or >310 for ≥ 1 second)  {
        ICEStop();
        return –1;
      }
 if(Generator Voltage Phase B <250 or >310 for ≥ 1 second)   {
        ICEStop();
        return –1;
      }
 if(Generator Voltage Phase C <250 or >310 for ≥ 1 second)   {
        ICEStop();
        return –1;
      }
 if(Generator Amps Phase A <0 or >350 for ≥ 1 second)   {
        ICEStop();
```

```
                return –1;
            }
        if(Generator Amps Phase B <0 or >350 for ≥ 1 second)   {
                ICEStop();
                return –1;
            }
        if(Generator Amps Phase C <0 or >350 for ≥1 second)   {
                ICEStop();
                return –1;
            }
        Output: Request Generator Frequency
        Input: Return Generator Frequency
        if(Generator Frequency <59.5 or >60.5 for ≥ 1 second)   {
                ICEStop();
            return –1;
            }
    }    // end ICEDiagnostic()



ThrottleUp(ICE-id, ICE-kW)  {
        Output: PML Generator Meter signal to CView (or equivalent) ICE controller to
                throttle up the ICE identified to the ICE-kW
    Input: Verification of control action.
    if(it worked) return 0;
    else {return –1;}
  }  // end ThrottleUp()

ThrottleDown(ICE-id, ICE-kW)
    Output: PML Generator Meter signal to CView (or equivalent) ICE controller to
                throttle down the ICE identified to the ICE-kW
    Input: Verification of control action.
    if(it worked) return 0;
    else {return –1;}
  }  // end ThrottleDown()
  }  // end main
```

3.3 Conclusion

Optimal dispatch can be designed with few modules, maintaining a simple hierarchy. During operation, main() is at the top of the hierarchy, DERDispatch() and AbsChillerModulation() are on the second tier, and all other modules are on the third (or fourth) tier. DERDispatch() makes all decisions about the operation of the electrical system and the profitability of the entire system, including the trade-off with PV and the thermal credit. It runs continuously during system operation. It may stop or start any equipment because of alarms or internal optimal dispatch algorithms contained in module code, as described above.

Principal among its tasks, aside from watching for alarms and stops, is optimizing dispatch. This includes load following during the weekdays. In the daytime off-peak (Saturday, Sunday, holidays), or under conditions of decreased load and rising PV output, DERDispatch() decides when and whether to trip the PV with PVTrip() or stop the ICE with ICEStop(). It does this by calculating the thermal credit per period, adding it to the cost to operate per period, and comparing this with the PV earnings for the period. When the PV earnings exceed the thermal credit, DERDispatch() calls ICEStop(). This algorithm comes from analysis completed in Task 2.

AbsChillerModulation() runs continuously on a separate program thread from DERDispatch() and makes all decisions about the operation of the thermal system. It ensures that set points of return and supply temperature are maintained for the cogeneration loop, the condenser water loop, and the chilled water loop. It does this by opening and closing bypass valves, ejecting more or less heat through heat exchangers, and operating the variable frequency drives on the cooling tower and the balance radiators.

Future versions of the DEIS design should map building load, PV production by month, absorption chiller output, etc., and store these operational data to allow trending. Use of trending data at decision time will help DERDispatch() make improved choices based on historical experience.

Task 4: Test Codes Using Simulated Data

4.1 Introduction

The purpose of this task is to test and improve the codes using data from field monitoring as a functional test platform to improve the algorithms and to redesign and rewrite code as necessary.

The "functional test platform" of RE's DEIS is the actual installation of 13 projects (to date) and the monitoring of the performance of these projects using precision monitoring devices and storage of all information so gathered in a secure database.[23] It is possible to test the functionality of the DEIS as described in tasks 2 and 3 against this body of data. This report will look at those areas in which the design's operation can be probed from the data collected, analyzing potential and actual technical, economic, and operational issues. This task seeks to lay out a methodology for assessing the impact of various situations' optimal dispatch, culled from the information provided by the command and control (C&C) metering system installed at each project site.

From the test platform data RE has analyzed, situations preventing optimal dispatch have three root causes:

- Lack of granularity
- Lack of efficiency
- Lack of interoperability.

Because optimal dispatch is measured in terms of the profitability of the system, this task will only point out the problem and recommend further work necessary to determine the effect on profitability of sub-optimal dispatch. Task 10 in the Option Year will make a more detailed quantitative analysis.

The purpose of this task is to account for non-optimal dispatch and to outline next steps. The rationale is to allow RE to make more accurate and more instantaneous assessments of operational profitability and thereby promote optimal dispatch where it is cost-effective. Following this introduction:

- Section 4.2 will discuss in detail each barrier to optimal dispatch, the impact of the barriers to optimal dispatch, and possible solutions.
- Section 4.3 will implement modifications to the algorithms and system code based on more realistic assumptions of system functioning.
- Section 4.4 will present final recommendations.

[23] Task 1 contains a detailed description of this "test platform" monitoring system, including a complete listing of system outputs.

Table 4.1-1: Table of Issues Inhibiting Optimal Dispatch

	Operations Not Yet Optimal				
Issue #	**Issue**	**Problem**	**Impact**	**Solution**	**Implementation**
1	Static On/Off Modified Dispatch	Time-clock on/off control, modified by Device 37	Lost revenue	A more flexible controller	Cost
2	Time and Power Output Granularity: Throttle Controllers	Throttle control only allows on or off	Lost revenue	A more flexible controller	Cost
3	Data Integration: Proprietary Data Vocabularies	System components use proprietary data vocabularies	Lost revenue	Data translator; DG data standard	Cost
4	Engine Efficiency: Heat Rate Curve	Field heat rate of engine unknown	Lost revenue	Test the field heat rate	Cost
5	CHP Thermal Capture: Actual Data	Actual ton-hours less than rating	Lost revenue	Adjust thermal credit	None
6	Auxiliary Load Efficiency	No VFDs, fans run full on	Lost revenue	Install VFDs	Cost
7	Load Management: ion Inrush Current	Inrush current spikes at system start up	Lost revenue	Use synchronous or improved controls	Cost

4.1.1 Issue 1

Static On/Off Dispatch is defined here as generator control automated by a time clock based on tariff schedules, without regard to operation of the building. As defined, this approach does not really exist in the field because RE must take non-export into account. The device implementation used by RE for non-export does not turn on the generator until the building load is greater than 105% of generator output. It also shuts the generator off if there is export (load drops below 105%) for 2 seconds or more. This form of dispatch should be designated as Static On/Off Modified Dispatch. This is the current approach used across the test platform.[24] The data used provides a type of static dispatch shape built up around a composite minimum output day. Static On/Off Modified Dispatch restricts the size of the generator coverage of load because load following is impossible. Also, this approach does not maximize revenue at the shoulder. It also requires restarting the system after a device trip.

4.1.2 Issue 2

The throttle controller (see Section 4.2.2.1) does not have the capability to throttle the engines up and down. Even if it did, there is still a question of whether the engine's controller, called CView, could carry out the control ordered by the throttle controller. This is partly an issue of interoperability (see Issue 3) because CView uses a proprietary data vocabulary (implemented in ASCII[25] text) that cannot send or receive communications without data translation. However, supposing translation were not an issue, CView is programmed to operate at 0% or 100% and nothing in between. Because RE has not used a controller capable of incremental output, it has not been able to test the ability of CView to carry out throttle control requests. The result of this situation is that the system has little power granularity. The optimal dispatch requires 1-kW increments in the power axis and 1-minute increments on the time axis. The system exhibits fine time granularity — the PML controller can monitor or control in fractions of seconds. Generation capacity, however, is not granular at all. Power output is on (200 kW) or off (0 kW) unless manually controlled. Revenue is lost at the margin. The test platform can only cut a square hole in the building load; potential revenues are lost outside of the square.

---

[24] "Test platform" represents RE's 13 operational sites dispersed across California.
[25] The American Standard Code for Information Interchange (ASCII) is a character set for computers.

4.1.3 Issue 3

Data Integration — and specifically, the use by component manufacturers of proprietary data formats — has a more subtle relationship to lost revenue. For example, the CView system that controls the ICE functioning only allows on or off operations; so even if a new controller with multiple kilowatt output levels were installed, it could not be controlled through CView. The potential for lost revenue would be identical to the previous one. Capturing this lost revenue means a cost both to replace the controller and to supplement CView or to integrate it using a data translator. In fact, a revised version of CView has been distributed in small-scale testing. These tests have revealed that the manufacturer still has not addressed our needs in this revision, and this upgrade *will not* be integrated in any RE systems as retrofits or future purchased units. Integration of each of the other components would be assessed case-by-case, based on what revenue is lost by non-integration and overall cost. To address the scenario envisioned in this issue, RE has begun to implement a single ad hoc solution, to be discussed in Section 4.3, that allows integration of most components.

4.1.4 Issue 4

Engine efficiency, the ratio of energy input to electricity output, needs to be measured in the field. Heat rates should be measured for a select sample of individual engines, with some study made of reasons for variability among them. This sample should be selected to be representative of the fleet of generators. Potential revenue that could be lost by not doing this calculation comes from miscalculation of the Throttle-Down Thresholds (see Section 2.3.5.3). In fact, accurate profitability assessment of engine operation — even at 100% operation — is impossible without accurate heat rate data. The straight-line heat rate "curve" used in Task 2 was an estimate based on an educated guess for the beginning (100% operation) and ending (25% operation) points. The generator manufacturer provided all other values.

RE has initiated substantial heat rate experiments working closely with the manufacturer to simulate the conditions that exist on its sites. Results of these experiments have been mixed and require more laboratory testing to better capture the site-specific conditions (ambient air inlet temperatures at reduced loads) that have direct effects on our heat rate.

The manufacturer sees great value in this work and is in the process of building a full-scale test area within its factory to exactly mimic conditions found in our sites. The completion of this test bed is expected in the next 90 days.

4.1.5 Issue 5

Data have shown that the absorption chillers may only produce to capacity intermittently, despite building chiller load (according to chiller load data in Task 2) calling for 100% operation during daytime hours. CHP thermal capture comes from a comparison of the manufacturer rating for thermal capture and actual ton-hours measured by a Btu meter on an actual installation. The accuracy of the Btu meter is being questioned. Further data and analysis are needed to posit a cause of and solution to the problem.

RE has recently purchased and deployed a more advanced Btu meter to address the issues addressed above. This new device will allow Btu accounting in both directions (i.e., RE provides heat or cooling to the host, and then the host returns cooler water that RE uses to cool its engines). This exchange requires a device that is capable of measuring transfer in both directions.

4.1.6 Issue 6

Auxiliary or “parasitic” loads are those that the system supplies from its own operation. Examples include all the pumps and fans and all measurement devices from the cogeneration, chilled water, and condenser water loops. None of the fans in the RE installations is controlled with a variable frequency drive (VFD), so they run at 100% all the time. This is inefficient and results in lost revenue from the "parasitic" effect of using system electricity to feed unnecessary operation. The solution, to the extent it is cost-justified and operationally feasible, is the installation of VFDs and other energy-efficiency equipment.

4.1.7 Issue 7

Induction inrush current occurs as a result of using an induction generator on the ICE, which draws a large amount of current when it starts, causing a demand spike in the building load. Depending on how high the building load is at the time, the current might increase the host customer's monthly demand charge. Because RE is the customer's energy service provider, customer revenue loss could easily equate to RE revenue loss.

Further in-depth study of this phenomenon is required to accurately quantify the effects of this condition. It will be contrasted with the use of synchronous generators at similar sites.

4.2 Issues Preventing Optimal Dispatch

4.2.0.1 Causes Underlying Non-Optimal Dispatch

From the test platform data RE has analyzed, situations preventing optimal dispatch stem from three root causes:

- Lack of granularity
- Lack of efficiency
- Lack of interoperability.

Control granularity is necessary to make the system flexible at the margin. The optimal system modeled in Task 2 and Task 3 was divided into 1-kW units for output and 1-minute increments of time. The basic unit is the kilowatt-minute. RE’s system operating in the field today lacks granular control. The control unit is not subdivided between 0% operation and 100% operation.

Engine efficiencies — heat rates — are not well documented. No testing has been done on the engines at any partial loads. Even at 100%, there is large variability among heat rates at different sites and for different Hess model 220 engines. This variability is not yet explainable. As a result, the operating data necessary for partial-load operation does not exist. This work is a pre-requisite to optimal control.

Parasitic loads are not controlled. Heat dump fans run whether they are needed or not. System generation resources are tied up unnecessarily by serving loads that do not enhance system functioning. This second form of inefficiency also causes revenue loss.

As discussed in Issue 3, there is little or no system interoperability because devices in the CHP system use differing proprietary data languages. Decreased functionality following from this lack of communications will result in higher costs than with a more fully interoperable system. Money must be spent to install and program converter boxes to allow all devices to communicate, and these costs must be borne by every project.

4.2.0.2 Cost of Non-Optimal Dispatch

Although there is insufficient data to estimate the costs of all causes of non-optimal dispatch, it is worthwhile to estimate revenues lost from issues 1 and 2 above. Because current systems cannot operate at the margin effectively, projects lose sales of electricity.

RE's Web site shows that the company typically sizes its generation from 50%–80% of the building peak load,[26] with the exception of the Fountain Valley PV site, which is less than 25% of peak at present.[27] Under certain scenarios, the generating capacity of a project can be dispatched sub-optimally.

Using a composite sketch drawn from the sites currently listed on the Web site, most systems achieve just under 47% coverage of the kilowatt-hours of the total used for the day polled (May 22, 2002), producing 29,668 kWh of 63,658 kWh total. Data from the C&C metering units point out that this may be misleading because it is not a peak day. Analysis of the data provided actually reveals that if the system were operating optimally — with 100% granularity throttle controllers, known heat rates, and by-the-minute data collection — it could, with existing generating resources, have produced 45,078 kWh, or 71% of the kilowatt-hours for the day. Because of the lack of granularity though, the system produced only 65% of electric revenue possible for the day. In essence, there exists a potential for one-third more operating revenue. These figures do not include the lost revenue from higher thermal credit available from higher levels of operation.

Capturing the lost revenue identified in Table 4.2-1 will require solving issues 1 and 2. This report will explore possible reasons for non-optimal dispatch in detail. The other issues that might lead to lost revenue include:

- Data interoperability: proprietary data vocabularies
- Engine efficiency: heat rate curve
- CHP thermal capture: actual data
- Auxiliary load efficiency
- Load management: induction inrush current.

---

[26] The URL is http://www.realenergy.com/. Click on "Distributed Generation Resource Center" and then on "Enterprise-Wide Network & Management System." Data for day-behind loads for solar PV, microturbines, and CHP systems are maintained.
[27] Sizing criteria for PV sites are limited by available facility roof area.

Table 4.2-1: Estimated Electric Revenues Lost Because of Non-Optimal Operation[28]

Facility	Type	Generating Capacity kW	Total Facility Usage kWh	RE kWh Produced	% RE Gen of Total	RE Max Possible kWh	RE Max Possible %	RE Optimal Dispatch %	RE Optimal Dispatch kWh
LA	2 x ICE 400kW w/CHP	400.00	13,309	4,139	31.1%	9,600	72%	62%	8,277
Long Beach	2 x ICE 400kW w/CHP	400.00	8,183	7,163	87.5%	9,600	117%	95%	7,365
Costa Mesa	5 x ICE 1000 kW w/CHP	1,000.00	31,355	13,287	42.4%	24,000	77%	77%	21,600
San Diego	2 x ICE 400kW w/CHP	400.00	9,257	4,511	48.7%	9,600	104%	71%	6,612
Marina Del Rey	2 x Micro-turbine 60kW	60.00	1,554	569	36.6%	1,440	93%	93%	1,224
			63,658	29,668	46.6%	54,240	85%	71%	45,078
				Revenues taken of total available:				65.8%	
				Revenues lost to sub-optimal dispatch:				34.2%	

4.2.1 Static On/Off Modified

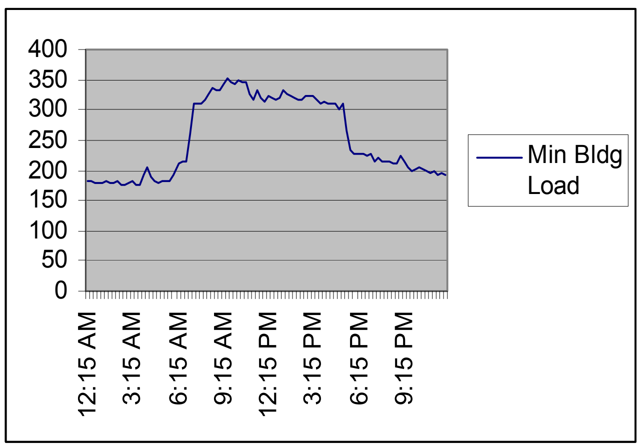


Figure 4.2.1-1: Minimum building load

Current dispatch is automated by time clock, based on tariff schedule, and modified by non-export device implementation. The sizing criteria call for generation to represent 50%–80% of peak load, depending on expected occupancy and other factors. In the composite examples, graphically detailed in this section, the building's peak load for the year is 674 kW. RE sized generation at two 200-kW ICEs, or 400 kW or 59%, of peak. The generation capacity is 114% of minimum building peak of 351 kW. RE also employs a 5% design margin to prevent export. If the building load drops below 420 kW for more than 2 seconds, the non-export device trips the lag (or marginal) engine, what we are calling ICE-2. Figure 4.2.1-2 shows what export would be on the minimum day, absent the non-export device.[29] The C&C module would limit operation to one engine and only from 6:30 a.m. to 9:00 p.m. in this example.

[28] All figures come from the RE Web site. No kilowatt-hour figures are available by period, so lost revenue must be estimated based on optimal use of generators beneath the building load shape. Facilities included are the only ones with load and generator data capability.
[29] Under RE's current export agreement, incidental export is not allowed, and the C&C metering units installed as part of the total test platform would simply cycle the ICE-2 off should demand near a minimum threshold.

To avoid conditions of the minimum load day, it is sensible to size overall generation at closer to 50% of peak load or even smaller — given static dispatch. But this operational consideration leads to lost revenue on days of higher building load. This is one of the strongest reasons for implementing optimal dispatch with load-following capabilities.

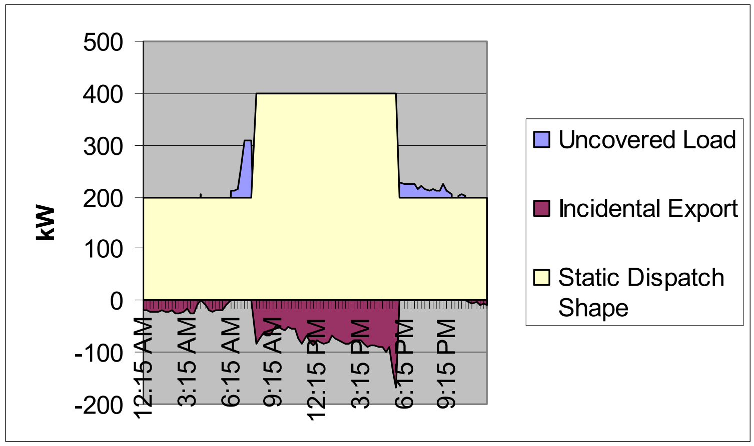


Figure 4.2.1-2: Static dispatch shape without operator control – minimum building load mark

4.2.2 Time and Power Output Granularity: Throttle Controllers

The optimal dispatch modeled in Task 2 and Task 3 is predicated on granular dispatch, as mentioned above; the power/time dispatch unit is the kilowatt-minute. Throttle control is the key component in breaking up the 200-kW power block of a single engine operating at 100%. RE has begun to assess two controllers so far: the Woodward controller and the Murphymatic.

The kilowatt-minute is a small, very granular power/time "square." The job of providing energy is analogous to filling a bucket: the smaller the gravel, the more the bucket can hold. Of course, smaller gravel costs more, but it provides more revenue every day of operation. RE's task, and that of the metering system, is to assess what level of granularity is cost-justified. It is clear, though, that granularity has the potential to maximize profit. Flexibility at the margin allows RE to better serve the building needs completely and also to maximize earnings.

Better throttle controllers provide the discrete step size at which power is output. A more robust throttle controller determines one axis of power/time granularity. Of course, granularity only matters when additional power can be provided at a profit at or near the limit of the fluctuating building load.

4.2.2.1 Woodward Controller

The Woodward EGCP-2, the only throttle controller currently used in RE installations, is a microprocessor-based engine generator control and energy management device. Key functions are engine control, synchronizing, real kilowatt load control, reactive kVAR control, generator sequencing, engine protection, generator protection, and communications. No automated throttle-up or throttle-down is available with the Woodward control; it only has capability to run the generator remotely at 100% or 0%, on or off. The lost revenue comes from the fact that load following (use of either ICE as a marginal unit) is impossible. The controller can only cut a square hole in the building load; leftover revenue outside of the square is missed.[30]

[30] In addition, it appears that ICE-1 should have turned on at 6 a.m. and turned off at about 10 p.m. (on the sample day) because the load between these times was greater than 400 kW. This could be an issue of scheduled time of use to run only on mid- and on-peak hours; otherwise, the responsibility must lie with faulty engine control. The scheduled time of use (if it is the explanation) should be rechecked because it is unlikely that the Throttle-Down Threshold would be higher than the ICE total output, especially if the thermal credit is included.

In this example, more than 50% of the kilowatt-hours that could have been generated were generated. Most of the lost revenue occurs off-peak, lessening its impact. The lost revenue includes reduced electricity production (kilowatt-hour sales to the customer) and reduced ton-hour sales from thermal capture. A more flexible controller is needed. The Woodward controller is at least partially responsible for the loss of revenue.

With a more flexible controller and automated control, it is also possible to increase generator sizing as a percentage of total building load. In Figure 4.2.2-1, the load is about 850 kW at the peak and above 700 kW during all on-peak hours, but the generation is limited to 400 kW. With better control, the project might afford 200 kW–300 kW of additional generation to capture more of the customer on-peak and mid-peak electricity usage.

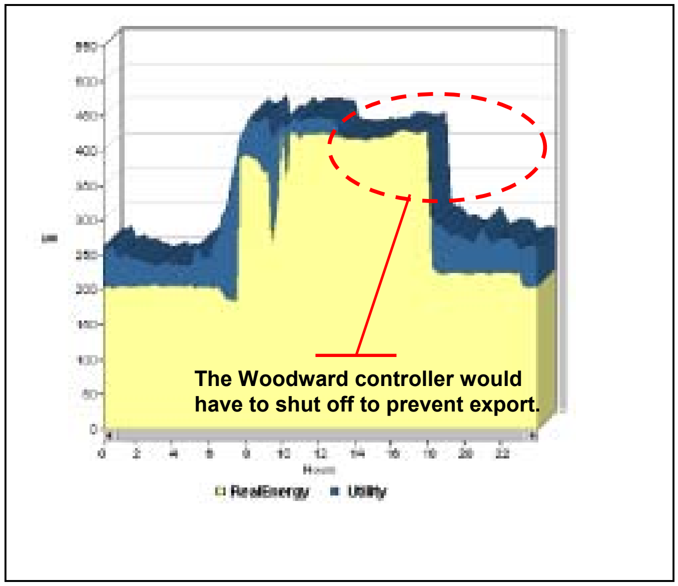


Figure 4.2.2-1: Lack of design margin

The metering system also shows that besides loss of revenue, the Woodward controller reduces operational flexibility. Even when small dips in building load occur, the Woodward controller must shut off to prevent incidental export.

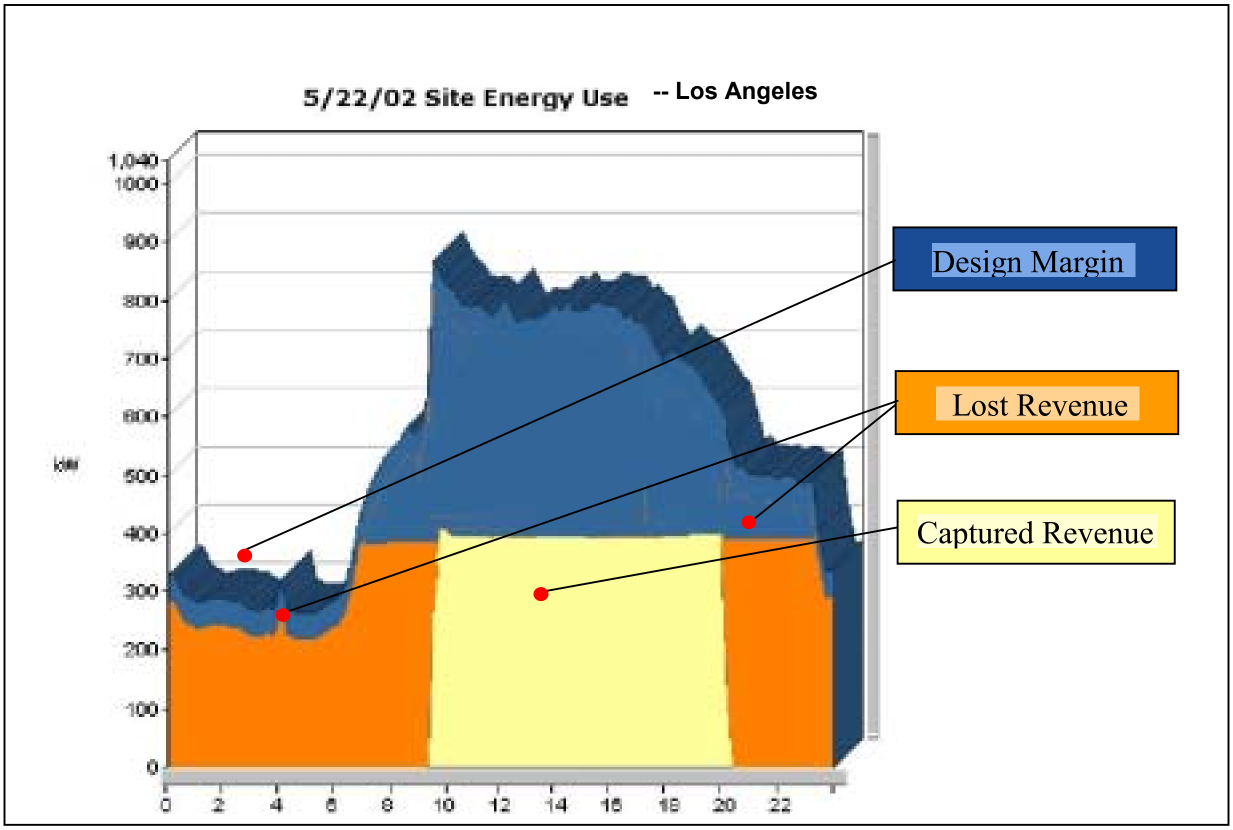


Figure 4.2.2-2: Lost revenue from non-granular throttle control

4.2.2.2 Murphymatic Controller

The Murphymatic controller AT-67207 24 VDC was reputed to have reliability equal to the Woodward controller, with greater operational flexibility. Three additional kilowatt output levels are offered beyond on and off. Dispatch is not optimal, still, but potentially lost revenues could be decreased, and some less crude load following will be possible. The levels assumed for lost revenue modeling are: 140 kW, 180 kW, and 210 kW (70%, 90%, and 105%, respectively).

Putting a lower limit to ICE operation at 140 kW still incurs revenue loss because all other tariff Throttle-Down Thresholds are higher than 140 kW in SCE under TOU-8 tariff. (See Section 2.4.5.) Given a throttle controller that can operate the engine remotely at any kilowatt output setting, RE operations should determine actual lower operational thresholds (Throttle-Down Thresholds) prior to deployment of optimal dispatch.

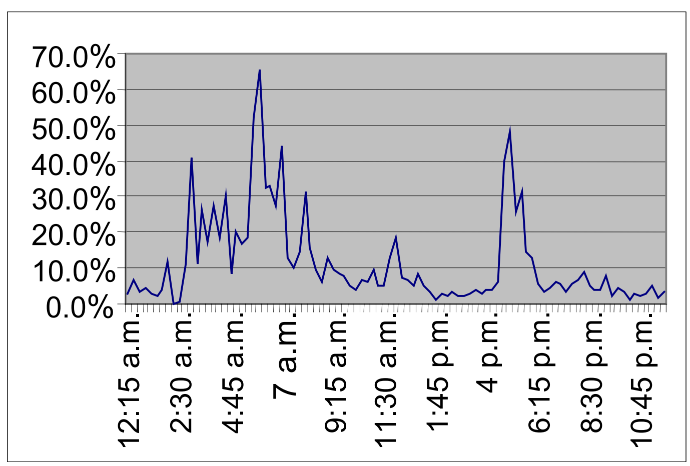


Figure 4.2.2-3: How often building load changed more than 5% in a period

This controller has been proved less reliable (compared with the Woodward). Failures have been attributed to heat and vibration. The solution proposed by the manufacturer is to better isolate the controllers. Modifications are under way and are expected to be ready for test in the next 30 days.

4.2.2.3 Building Load Fluctuations

Frequent changes in building load point out the shortcomings of static dispatch. If building load dips into the 5% buffer of the design margin for 2 seconds or more, the non-export device implementation is supposed to shut off the system. This, as mentioned above, prevents operation near the margin. When load fluctuates rapidly, particularly when fluctuation is greater than 5% of total, a static approach will lead to lost revenue. This occurs most often at the "shoulders" of the building load: 5–7 a.m. and 4–6 p.m. Automatic load following would prevent nuisance tripping and lost revenue because of coarse granularity.

4.2.2.4 Optimal Control

Optimal control is described in detail in Task 2 and Task 3. It is dispatch of 1 kW per 1 minute limited only by profitability on the lower end (the Throttle-Down Thresholds) and the ICE output on the upper end (110% or 220 kW). What this means is that the system is free to serve the building load at the maximum range allowable by the generator. Optimal control approaches the point of zero lost revenue. It cannot actually arrive at zero lost revenue because of limitations of the generators and the relative uncertainty of building load fluctuation. At present, the test platform has no throttle control system capable of kilowatt-minute incremental control. The primary barrier to optimal control is the expense to implement it and the technology available. Non-optimal control causes loss of revenue. These improvements and subsequent increases in revenue will offset additional costs and justify retrofitting the existing fleet.

4.2.2.5 Comparison of Dispatch Scenarios

Based on analysis of the data from RE's test platform, calculations of optimal dispatch can be accomplished by pegging revenue loss to coarse control granularity, comparing revenue loss from three options:

- Static On/Off Modified Dispatch
- Dynamic Multi-Setting Dispatch
- Optimal Dispatch.

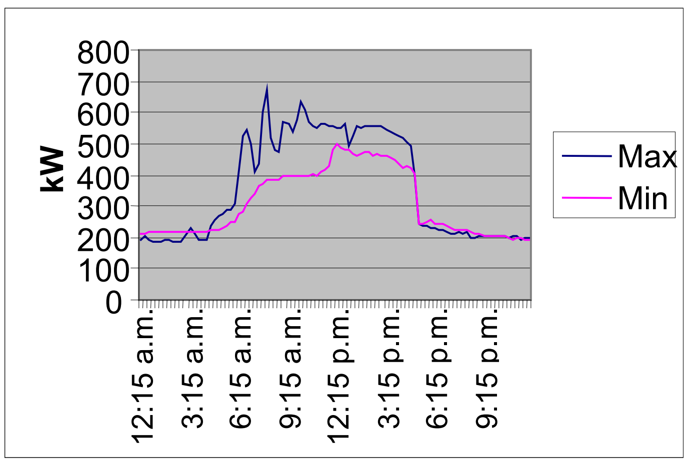


Figure 4.2.2-4: Days of min and max building load change exceeding design margin

If building load stayed level during the day, or if export were unlimited, building and dispatching generation to serve a load would be easy: the owner-operator could simply size the generators to run at 100% all day. The more a load fluctuates, the more necessary it is to have fine-grain control. The larger (in kilowatts) and more rapid (in minutes) the fluctuation in building load, the finer the power granularity required to serve the load optimally. To get metrics on the whole range of load changes with a minimum of modeling, from a year of building data we chose days of maximum and minimum building load change, under the assumption that these would represent the limit cases, with all others falling in between. Criteria for the choices were weekdays with the minimum and maximum number of variations greater than 5% of load from one period to the next. The minimum was 5 changes greater than 5%; the maximum was 27 changes greater than 5%.

4.2.2.6 Modeling Assumptions

This report, as mentioned in the opening, is meant to establish the facts surrounding possible situations of non-optimal dispatch and their severity. The actual modeling calculations will be carried out for Task 10 of the Option Year. This report will lay out modeling assumptions necessary to model non-optimal dispatch without actually carrying out the calculations. For this reason, some adjustments may need to be made at calculation time.

As data have shown, the profitability of the day might have to do in part with the kilowatt minimum and maximum of the day and how they relate to engine size; this has nothing to do with how much load change the day exhibits. To eliminate this issue from the results, the modeling assumption will use the percentage of increased revenue divided by the total revenue available as a basis for comparison. The following assumptions might be made as the basis of analysis of throttle control:

- All scenarios involve dispatch of the Hess Model 220 Rich Burn 200-kW ICEs.
- All dispatch scenarios are automatic, i.e., they do not involve manual control.
- Lead and lag engines are referred to as “ICE-1” and “ICE-2” respectively.
- There is no incidental export.
- There is a 5% design margin.
- Static On/Off Modified Dispatch assumes control by the Woodward controller.
- Dynamic Multi-Setting Dispatch assumes control by the Murphymatic controller, with settings at 0 kW, 140 kW, 175 kW, 200 kW, and 220 kW (0%, 70%, 88%, 100%, 110%).
- Optimal dispatch assumes kilowatt-minute granularity from 0 kW–220 kW, limited only by profitability.
- Murphymatic and Woodward throttle settings cannot be reset every day (much less every hour), and once set must more or less stay that way.
- Changed throttle settings are to take effect within one period.
- All electric revenues are based on the TOU-8 summer tariff of SCE. Summer season is defined as 12 a.m. on the first Sunday in June to 12 a.m. on the first Sunday in October. In summer, the on-peak tariff applies from noon to 6 p.m. on weekdays, excluding holidays. Summer mid-peak is charged 8 a.m. to noon and 6 p.m. to 11 p.m.; all other hours are off-peak. Rates are as follows: summer on-peak: $0.1829 per kWh, summer mid-peak: $0.0996 per kWh, and summer off-peak: $0.0867 per kWh.
- The demand charge on TOU-8 is: summer on-peak: $23.95, summer mid-peak: $9.20, and summer off-peak: $6.40.[31]

[31] Total demand charge is: facilities-related component: $ 6.40 per kW; time-related component (to be added to facilities-related component): all kilowatts of on-peak demand, $17.55 per kW, plus all kilowatts of mid-peak demand, $2.80 per kW, plus all kilowatts of off-peak demand, $0.00 per kW.

- All thermal revenues are based on displacing an 80-ton chiller with an efficiency of 0.75 kW/ton at full load. (See Task 2, Section 2.2.2.) These numbers serve as a proxy for the actual RE price per ton-hour to the customer: summer on-peak: $0.1374, summer mid-peak: $0.07484, summer off-peak: $0.0651.
- Summer on-peak operations (under optimal dispatch) can run below 140 kW (see discussion in Section 2.2.2).

4.2.2.7 Static On/Off Modified Dispatch

The algorithm for Static On/Off Modified Dispatch, to match building load and avoid incidental export, is: At the commencement of mid-peak tariff, C&C checks building load. If it is greater than 210 kW (generator capacity plus 5% design margin), it runs ICE-1. When load drops below 210 kW or mid-peak tariff ends, it shuts off ICE-1. At the commencement of on-peak tariff, C&C checks if building load is greater than 420 kW; if so, it runs ICE-2. When load drops below 420 kW or on-peak tariff ends, it shuts off ICE-2.

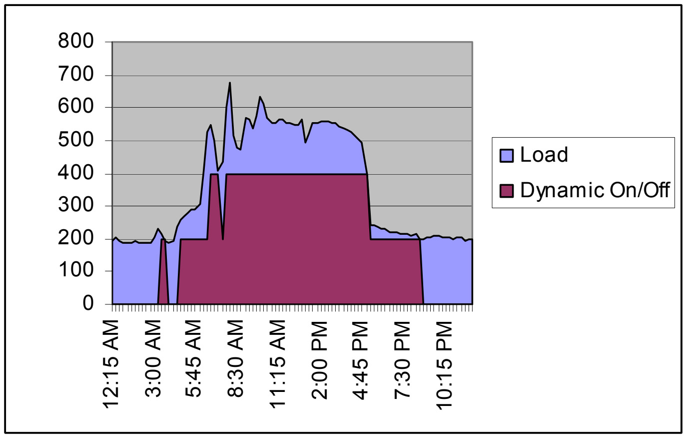


Figure 4.2.2-5: Static On/Off Modified Dispatch

Besides lost revenue in overall sizing and during daily operations, another serious limitation of this dispatch algorithm is that the engines may stop and start much more frequently in a day than is desirable. At 4:30 a.m. and again at 7:30 a.m. (on the day depicted in Figure 4.2.2-5), the marginal engine shuts off because the load dips below the threshold for only one or two periods. As mentioned in Section 4.2.2.3, this may happen multiple times per day on days of frequent load fluctuation.

4.2.2.8 Dynamic Multi-Setting Dispatch

The algorithm for Dynamic Multi-Setting Dispatch is the same as for Dynamic On/Off except it has more settings. In addition to the 200-kW output, the multi-setting controller allows operation at 140 kW (147 kW with 5% margin), 180 kW (189 kW with 5% margin), and 210 kW (221 kW with 5% margin).

On peak, the system now produces 420 kW, a 5% improvement in profitability; it can also run all night without causing incidental export. In fact, during this particular 24-hours, no incidental export

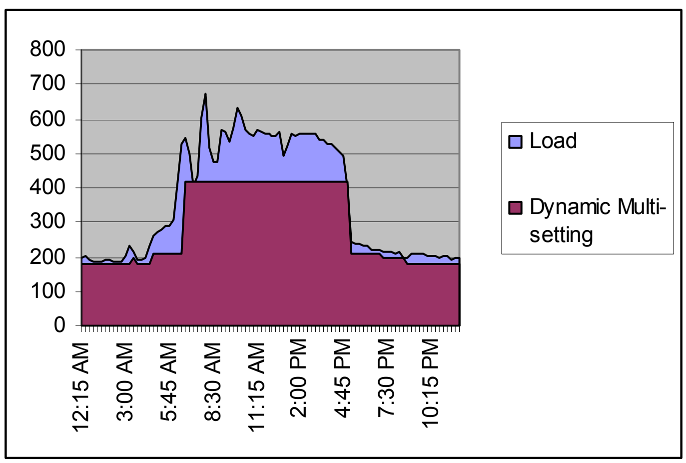


Figure 4.2.2-6: Dynamic On/Off Dispatch

occurs, and there are only two design margin warnings. Better yet, it does not shut engines off because of small downward fluctuations; it adjusts its own output lower to match.

One operational constraint to dynamic and optimal dispatch is that in operating along an expanded range of generator capacity outputs, and therefore at increased heat rates at output levels below 100%, there is a risk in aggregate that overall system efficiency will decline below 42.5% — the level required for RE to maintain its status as a qualifying facility (QF). For a number of policy reasons that are outside the scope of this report, that would be undesirable. Annual efficiency of the CHP systems should be tracked and treated as another limitation on optimal dispatch.

4.2.2.9 Optimal Dispatch

The algorithm for Optimal Dispatch is: Throttle up or down at 1-minute increments to match 95% of building load. If load is greater than the maximum generator capacity, run at maximum. The optimal dispatch would need to be able to reduce output in less than 2 seconds to prevent export. This allows the system to maximize profit at all times of day and night.

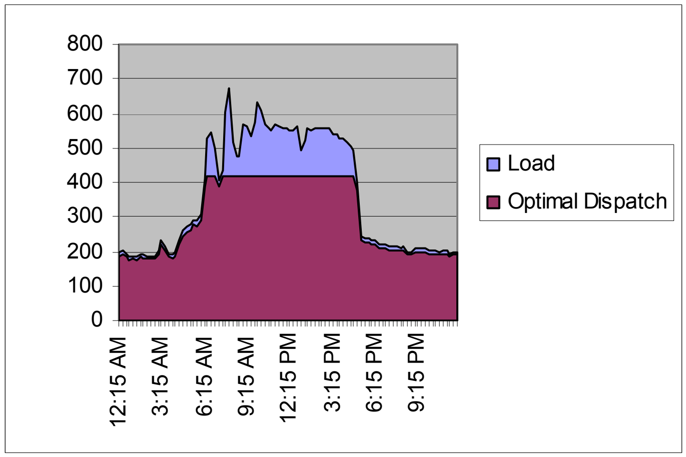


Figure 4.2.2-7: Optimal Dispatch

Taken as an enterprise-wide approach to C&C, the optimal dispatch would allow very aggressive system sizing. Rather than sizing the system at 50% of load, with optimal dispatch it could be more economical — depending on load shape and utility tariff — to size it at 70%–90%. Against technological considerations, RE must balance the issue of tenant occupancy, which may decline after installation of the system. Thus, financial prudence, based on the likelihood of a decrease in occupancy, must be part of the decision.

There are limits to Optimal Dispatch. On the high end, as shown in 4.2.2-7, the system is limited by the building load (less design margin) and generating capacity. On the low end, the Throttle-Down Thresholds limit the dispatch, as discussed in Section 2.3.5.3.

4.2.3 System Interoperability: Proprietary Data Vocabularies

Interoperability becomes an issue in the context of complex systems containing devices made by different manufacturers. Many component manufacturers use proprietary data formats, in part because there are not specific standards for distributed energy systems and in part for competitive reasons. This became a major issue for RE in constructing the C&C metering system that was deployed on the test platform. The cost associated with non-communicating devices is that it triples the complexity of the system to have three devices that each use a different data language. Additional complexity will mean additional development and ongoing support costs. It would be less expensive, both at start-up and during operation, if all of the components of a system used a single data language designed to a standard. Currently, there is no distributed energy data vocabulary. As RE's experience shows, it is necessary to translate data across devices to achieve interoperability. Data translation takes programming up front to do ad hoc conversion, mapping data items from one code set to another. Once that work is complete, however, there is no additional cost unless additional devices are added to the system.

4.2.3.1 Data Translation

With its first CHP systems in the field, RE learned that its utility Main and Generator meters could not talk to Siemens or Andover building control systems, these could not talk to the engine control system (CView), and none of the three could talk to the chiller controller. Each of the control sets used a different data language, so none was compatible with the others.

Once RE had decided on its Generator and utility Main Meter manufacturer,[32] it began to search for a common way for its peripheral devices to exchange information. It found a "de facto standard" for communication among automation devices in the open system MODBUS. MODBUS is not a data language or data vocabulary, however; it is a protocol for the exchange of information among multiple client and server automation devices.

To achieve industry-wide device interoperability, MODBUS will be insufficient. Its "user-defined" function codes are not the basis of a standard data vocabulary. It would be much preferable to base the standard data vocabulary for distributed energy on the de facto standard for Internet data vocabularies, XML — the eXtensible Markup Language. That would not replace MODBUS but would supplement it at a higher level. One of the great benefits of using an XML vocabulary is that it can be read and understood by everyone in an organization (if the tag names are well-chosen), whereas a set of MODBUS user-defined codes are incomprehensible without a translation sheet to explain the meaning of each numerical code. It is unclear at this time whether the IEEE effort on distributed energy communications, P1614, will address issues of device interoperability through a standard data vocabulary.

To integrate the multi-engine controller, CView (the Hess proprietary engine control data format), the Asic chiller controller, and the (Siemens or other) building controls, RE employs programmable protocol converter boxes. Niobrara Research and Development Corporation (NR&D) manufactures the boxes. Each engine has its own NR&D box, as does the chiller controller and building control. Because the system is wired to handle both RS 485 and RS 232, a device called "COM 128" (also by NR&D) is used to convert between these two standards.

This is a good ad hoc solution to the problem of data translation. The distributed energy industry, however, needs a standard. Until all distributed energy device manufacturers use the same data vocabulary, installing will continue to be non-interoperable until a translator capability is installed. That raises the cost of the project and, ultimately, is damaging for all parties involved.

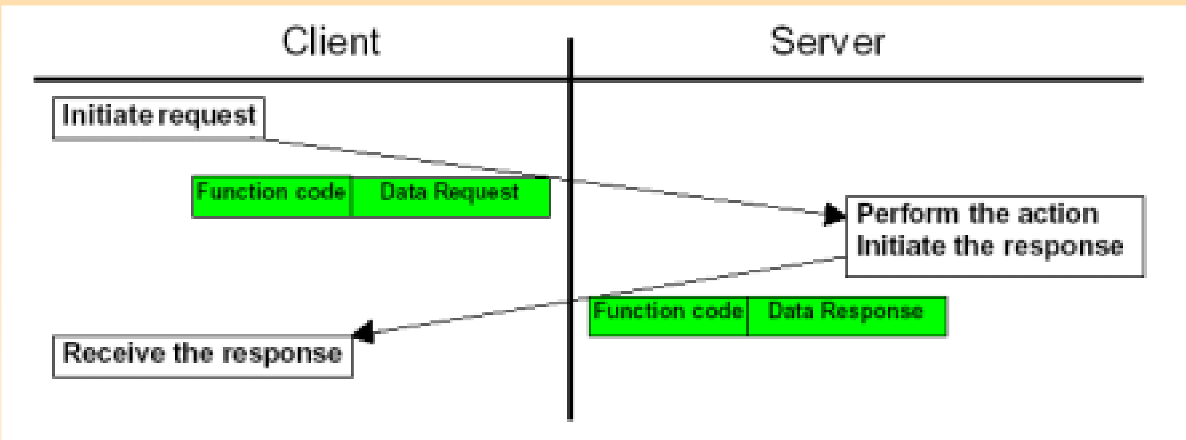
---

[32] Power Measurement, Limited. For a more detailed description, please see Task 1, "Definition of Information and Communications Requirements."

MODBUS: A Protocol for Connecting Automated Devices

MODBUS is an application layer messaging protocol that provides client/server communication between devices connected on different types of buses or networks. MODBUS has been a de facto standard for serial devices since 1979, and it continues to enable automation devices to communicate. More recently, it has been expanded to allow communication over the Internet.

MODBUS is a request/reply protocol and offers services specified by function codes. Some codes are built-in; others are user-defined. Requests come from clients requesting services; replies go out from the server, as depicted below:



When a message is sent from a client to a server device, the function code field tells the server what kind of action to perform. For example, a client can read the on/off states of a group of discrete outputs or inputs, or it can read/write the data contents of a group of registers. If multiple actions need to be performed, the client can add sub-function codes. The data field of messages sent from a client to server devices contains additional information that the server uses to take the action defined by the function code. This can include items such as discrete and register addresses, the quantity of items to be handled, and the count of actual data bytes in the field. The function code alone specifies the action. If no error occurs related to the MODBUS function requested by the client, the data field of a response from a server to a client contains the data requested. If an error related to the MODBUS function requested occurs, the field contains an exception code that the server application can use to determine the next action to be taken. When the server responds to the client, it uses the function code field to indicate either a normal (error-free) response or that some kind of error occurred (called an exception response). For a normal response, the server simply echoes the original function code.

4.2.3.2 Engine Control and Dispatch

The CView system that works in conjunction with the Woodward controller to control the Hess ICEs only allows for on or off operations. So even if a new controller with multiple kilowatt output levels were installed, it could not be controlled through CView. Improving operations and decreasing lost revenue from static dispatch requires expenditure both to replace the Woodward controller and to bypass (or augment) CView. A data translator cannot replace control of the engines; it can only make engine data available for other processes.

RE has researched a system in which CView would be supplemented by an additional PLC and sensors tied directly to the engines. This would allow automated dispatch and load following at a distance in 1 kW/minute time/power squares, as called for by optimal dispatch. The cost has thus far appeared to be prohibitive. Unless some other multi-engine controller (besides Woodward and Murphymatic) can be found or RE uses a different engine and built-in control that allows flexible operations, completely optimal dispatch may remain elusive.

4.2.4 Engine Efficiency: Heat Rate Curve

Heat rate is one of the most important components of the profitability calculation for the DEIS operation. As heat rate rises, the cost per kilowatt-hour rises too — not linearly, but geometrically (shown in Figure 2.3.5-2). To determine heat rate accurately at multiple kilowatt output levels, field testing of heat rates, along with chemical analysis of the Btu content of the gas, should be performed. Once the heat rate characteristics of several units in the field are measured, this actual heat rate curve could be applied to all other units in similar installations.

The revenue lost by not doing this calculation comes from miscalculation of the Throttle-Down Thresholds (see Section 2.3.5.3). In fact, accurate profitability assessment of engine operation is impossible without knowing the actual heat rate curve. The straight-line heat rate "curve" used in Task 2 (shown in Figure 2.3.5-1) was an estimate based on operating experience and data from the manufacturer for the beginning and ending points. All other values were essentially estimated by interpolation.

4.2.5 CHP Thermal Capture: Actual Data

The engine manufacturer Hess states that the thermal output of the Rich Burn Model 220 is 978,000 Btu/hour, or 81.5 tons/hour. Checking this number against delivered tons of cooling will give an idea of the efficiency of thermal delivery and the quantity of losses in the cogeneration and chilled water loops combined (i.e., from the engines through the absorption chiller to the building). On the one hand, the manufacturer numbers may be higher than numbers from field operations because they do not include delivery losses; on the other hand, the manufacturer numbers may be lower than operation in the field if the manufacturer heat rate is lower than the actual field heat rate. At each of its sites, RE should be able to measure gas flow in, electricity, and chilled water out to get the actual field-delivered heat rate and system efficiency.

RE has now integrated these devices at four sites, and there still is not enough historical data to make accurate assumptions.

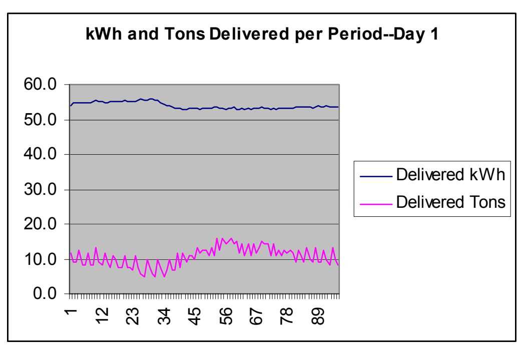


Figure 4.2.5-1: Electric and thermal output on a minimum load day

The DEIS has collected information from the first project that has the Onicon Btu meter installed. The following charts are taken from the first 3 months of operation, January through March 2002. It is uncertain, therefore, whether the building cooling load required 100% of the chilled water produced by the absorption cooling system at any time during the months studied. It is likely that it did, however, because the absorption chiller is running as base load cooling for the building. Given these caveats, the following data still provide some interesting insight into how the system was operating and point out some areas that need further research to determine their cause and their effect on profitability. On a cooler winter day, the second generator never starts, and the cooling load is fairly flat.

Because the data in Figure 4.2.5-1, are in periods, the kilowatt-hour totals are divided by 4; the system is delivering 55 kWh per period, or about 220 kW per hour. The cooling load shows a "peak" from noon to 6 p.m., as we would expect. The dip from 4 a.m. to 8 a.m. is probably due to the action of the economizers cooling with outdoor air.

Data collected by RE's metering package allowed RE to conduct thermal analysis. The primary limitation is the limited data set, which only runs from mid-January to mid-March — the only data available at that time. The building electric load on a more typical day, even in the winter, is usually more than 400 kW during peak hours, and both engines can operate below the design margin. Chiller loads are less documented. It appears that doubling the kilowatt output by starting the second engine did not double the cooling delivered to the building. It could be that the building cooling load depicted in Figure 4.2.5-2 is not great enough to require cooling from both engines (indicating that the unused heat was sent to the balance radiators). Data from summer operations should help answer this question and should show a doubling of cooling tonnage after the second engine comes on. If not, it would be sensible to discover what was happening to the additional heat.

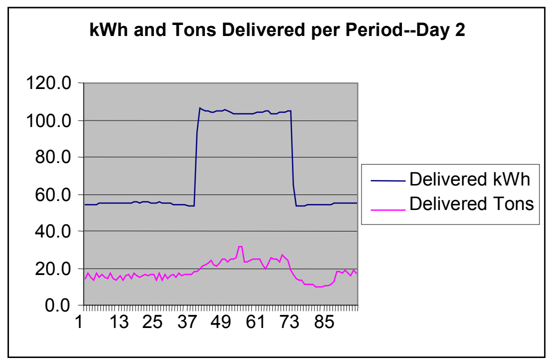


Figure 4.2.5-2: Electric and thermal output on a medium load day

A closer look at the data (in Figure 4.2.5-3) reveals an hour (4:30 p.m. to 5:30 p.m.) in which the production of chilled water is 97.6% of the manufacturer specifications for thermal output:

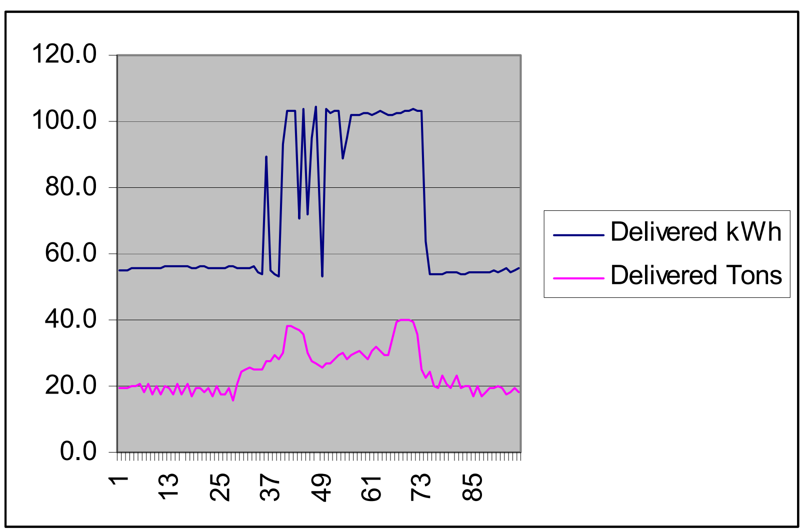


Figure 4.2.5-3: Incidence of maximum thermal output

it is 159.2 tons out of 163 when both engines are operating. The hour of 10 a.m. to 11 a.m. on the same day achieves 92.5% of thermal output.

Using the manufacturer thermal output as 100%, the overall efficiency of the thermal capture at this installation is 59%. Why is it so low? The definitive answer may help RE capture 30%–40% more revenue from its thermal credit.

4.2.6 Auxiliary Load Efficiency

Auxiliary loads, also called "parasitic" loads, are the loads that the system adds from its own operation; examples include all the pumps and fans from the cogeneration, chilled water, and condenser water loops. Few of the fans are currently of VFDs, so they run at 100% all the time. This is an inefficient operation and results in lost revenue from the parasitic effect of using system electricity to feed system operation. Currently, RE has not integrated any VFDs into its system operations at the 13 sites operating as of the date of writing. RE does recognize this as a form of revenue loss but has not completed its cost-benefit analysis. Task 10 in the Option Year will include a cost/benefit evaluation for VFDs.

4.2.7 Load Management: Induction Inrush Current

The data on existing operations show demand spikes at all sites currently using an induction generator. Induction and synchronous generators operate quite differently in terms of the grid. A synchronous generator spins up to the speed of the grid (60 Hz) and then interconnects; the induction generator interconnects and draws grid current to start up the generator. For this reason, the induction generator draws a large amount of current just before it starts, like an induction motor. The current inrush causes a demand spike in the building load. The cost associated with the induction inrush depends on how and whether the spike increases the host customer's demand charge. Utilities use pulse systems at larger industrial and commercial facilities to measure kilowatt demand every 15 minutes. If induction start-up occurs while the utility is pulsing the customer, the customer’s demand charge could be significantly higher.

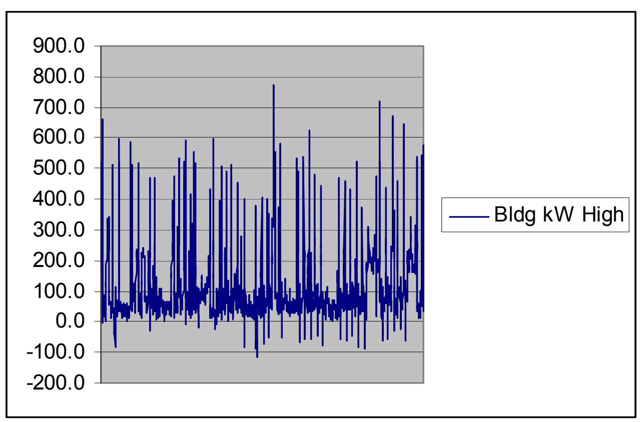


Figure 4.2.7-1: Periodic high kilowatt values for 3 months (building net of generation)

The DEIS system captures and displays high, low, and mean values for kilowatts from the total values it captures during a 15-minute period. Figure 4.2.7-1 shows the building load, net of generation. The data come from winter load, January through March. A look at the same period from the previous year, with building load alone (Figure 4.2.7-2) shows the effects of generation: most of the values in the first figure are less than 100 kW, showing that generation is cutting building kilowatts 200 kW–400 kW (depending on whether one or two engines are operating). Values more than 210 kW indicate that the generators are functioning non-optimally because we would expect an optimal operation to cut loads as soon as they exceed the engine kilowatts plus a 5% design margin, assuming that the total generation is sized to meet 100% of minimum kilowatts (which is approximately 400 kW, as shown in Figure 4.2.7-2). Values more than 550 kW in Figure 4.2.7-1 are examples of inrush current, with the worst case creating a 770-kW spike. Many of the values more than 300 kW are likely induction spikes as well, though deciding which requires separating those times when the engines are not operating from the times when they are. Values less than 0 kW are examples of incidental export.

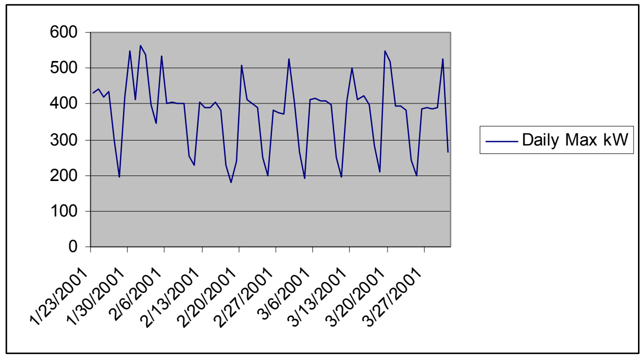


Figure 4.2.7-2: Daily maximum kilowatt building load for the same 3 months

This analysis, though it clearly isolates some operational issues, cannot yet quantify how much they cost either to the customer or to RE. An analysis is required to isolate which spikes (if any) are recorded by utility kilowatt meters, at which level they're captured, and what overall additional cost they create. Once these costs are captured, it will be possible to determine what revenue is available to remove or eliminate the cause — whether by replacing induction motors with synchronous ones, installing advanced controls, or (if there is no cost) doing nothing.

4.3 Changes to Algorithms and Code

The heart of the optimized system reported in Task 3 ("Develop Codes and Modules for Optimal Dispatch Algorithms") is the function DERDispatch(). This function depends on its ability to monitor system performance and to control resources automatically to optimize dispatch. As noted in Section 2, however, RE currently does not have a controller capable of automated dispatch, beyond a simple on-off timer function. It has already been mentioned that Static On-Off Dispatch results in revenue loss, though the magnitude of loss has not been quantified. DateTime() performs the clock function, but it should be combined with DERDispatch() and ICEStart(), ICEStop(), and PVTrip() in a single static dispatch module. The CView system for engine self-diagnostics and on/off control will be central to this retooled module. The building control system should be represented, with its interface through the NR&D converter. The absorption chiller operation is currently controlled by the Asic controller, which communicates with the rest of the system through the NR&D converter that translates from the proprietary ASCII format to MODBUS user-defined codes. Therefore, all chiller operations should be contained in a single module and interface through the NR&D box, as discussed in Section 4.2.3. Finally, these three modules should tie in the PML Generator and Main devices for enterprise-wide services, including Integration(), Metering(), Monitoring(), Billing(), and Alarms(), under the EnterpriseServices() module. Pseudo-code for these submodules will not be included. EnterpriseServices() has the capability to run multiple sites from a single central location.

The result is a simpler and less powerful system for the DEIS, which captures a fraction of the revenue potentially available to it. This is approximately what exists in the field today. In Figure 4.3-1, the upper-level modules are in the boxes with corners rounded; the submodules are contained within them. Thus, the DEIS program hierarchy looks like this:

Level	Function Hierarchy
1	main()
2	StaticDispatch()
3	DateTime(), ICEStart(), ICEStop(), PVTrip(), ICEDiagnostic()
2	ChillerDispatch()
3	ConstructAbsChillerObject(), TestAbsChillerObject(), AbsChillerStart(),
3	AbsChillerStop(), AbsChillerModulation()
2	EnterpriseServices()
3	Integration(), Metering(), Monitoring(), Billing(), Alarms()
2	BuildingCom()
3	DEISio()

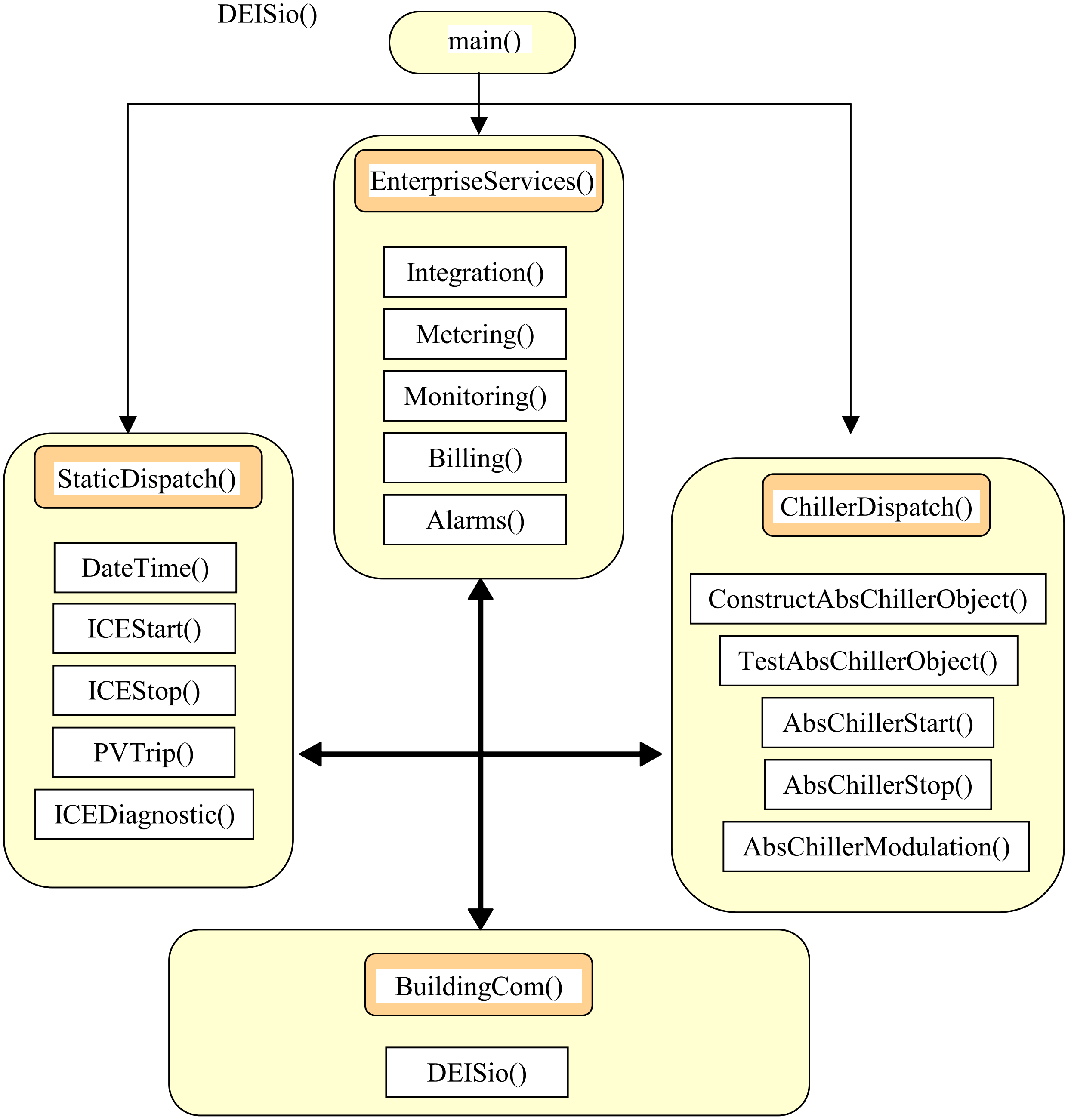


Figure 4.3-1: The DEIS revised flowchart

Code for Dispatch Sequence

The pseudo-code included here is much simpler than the pseudo-code in Section 3.2.4. It has been simplified by the current real-world obstacle RE faces without a controller that can provide load following. The function called DERDispatch(), which did load following in the code in Task 3, has been replaced by a much simpler function called StaticDispatch(). Note that this code has no ThrottleUp() or ThrottleDown() function because in this new code the engines run either 100% on or off. Another difference in this revised code is that input data is not passed as a parameter. Using the extensions provided in the C++ language, it would be possible to make the objects part of the same class as the functions (called "member methods" in object-oriented programming) that need to use them. (Note: Class declarations are not included in this pseudocode.) For this reason, the functions in this code have no return values. Otherwise, the code in the functions DateTime(), ConstructAbsChillerObject(), AbsChillerModulation(), ICEStart(), and ICEDiagnostic() is unchanged from the code in Task 3. The list numbers are to simplify reading the text, they are not part of the code.

Code:

```
 main()  {                   // begin main()
                             // construct objects, declare variables (not shown)
DateTime();                  // call DateTime()

StaticDispatch();

        DateTime()  {            // begin DateTime()
            Get PML Generator Meter current date and time;
            // Now use the info from PML to construct DateTimeObject
            DateTimeObject.year = Year;      // assign local variable “Year” to the
                                                       //DateTimeObject data member “.year”
            DateTimeObject.month = Month;// same as above
            DateTimeObject.day = Day;
            DatetimeObject.hour = Hour;
            DateTimeObject.minute = Minute;
            DateTimeObject.second = Second;
            // create an integer “time” from year, month, day, hour, minute, second
            DateTimeObject.time = integerRepresentationOfTime() // not defined
            DateTimeObject.dayofweek = DayofWeek;
            Process: Determine if it is a Sunday or Holiday = 0, Saturday = 1 or a
            NonHolidayWeekday =2 and assign result to OccupancyValue;
            DateTimeObject.occupancyvalue = OccupancyValue;  // 0, 1, or 2
            Process: Determine ApplicableElectricRateTariff
            DateTimeObject.tariff = ApplicableElectricRateTariff;
            // Get internal constants for beginning and ending time of use
            DateTimeObject.begin = ScheduledTOUBeginTime;
            DateTimeObject.end = ScheduledTOUEndTime;

            // No return needed because DateTimeObject is available internally;
        }                    // end DateTime()
```

```
StaticDispatch()   { // StaticDispatch() has access to the DateTimeObject internally
                     // begin StaticDispatch(), which will run until system shuts off

          Output: Request OK to run generator flag status from host building control
          Input: Receive OK to run generator flag status from host building control
       Decision: Is OK to run generator flag status true?
                  Yes: Continue
                  No: Alarm, wait and try again in 1 minute.
          // make sure this is a valid time of use
          if(DateTimeObject.time >DateTimeObject.begin and <DateTimeObject.end )
                  ICEStart();
          else
                  ICEStop();

} // end StaticDispatch

  ConstructAbsChillerObject()  {                    // begin function

       // assign system monitored results to object data members
       Output: Request Cogeneration Supply Water pump amps
       AbsChillerObject.CogenSupplyPumpAmps = Cogeneration Supply Water pump
amps;
       Output: Request Condenser water pump amps
       AbsChillerObject.CondenserPumpAmps = Return Condenser water pump amps;
       Output: Request Chilled water pump amps
       AbsChillerObject.ChilledWaterPumpAmps = Chilled water pump amps;
       Output: Request Absorption Chiller Enabled flag status
       AbsChillerObject.AbsChillerEnabledFlag = Absorption Chiller Enabled flag status;
       Output: Request building chilled water demand.
       AbsChillerObject.BldgChilledWaterDemand = Building chilled water demand;
       Output: Request chiller capacity control valve open percentage
       AbsChillerObject.ChillerCapacityControlValvePct = Chiller capacity control valve
       open percentage
       AbsChillerObject.CoolingTowerBypassValvePct = Cooling tower bypass valve open
       percentage

       Output: Request Cogeneration Supply Water Temperature
       AbsChillerObject.CogenSupplyTemp = Cogeneration Supply Water Temperature;
       Output: Request Cogeneration Return Water Temperature
       AbsChillerObject.CogenReturnTemp = Cogeneration Return Water Temperature;
       Output: Request Condenser Water return temperature
       AbsChillerObject.CondenserWaterReturnTemp = Condenser Water return
       temperature;
```

```
            Output: Request Condenser Water supply temperature
            AbsChillerObject.CondenserWaterSupplyTemp = Condenser Water return
            temperature;


            Output: Request Chilled water return temperature
            AbsChillerObject.ChilledWaterReturnTemp = Chilled water return temperature;
            Output: Request Chilled water supply temperature
            AbsChillerObject.ChilledWaterSupplyTemp = Chilled water supply temperature;

            AbsChillerObject.ChilledWaterTempDifference =
            AbsChillerObject.ChilledWaterReturn – AbsChillerObject.ChilledWaterSupply;

                Output: Request MMBtu of cooling delivered to user
                AbsChillerObject.DeliveredCooling = MMBtu of cooling delivered to user;

                // No return value needed because the AbsChillerObject is available internally


        }  // end ConstructAbsChillerObject()


      AbsChillerModulation (ICEStatusFlag)  {  // begin AbsChillerModulation()

            // declare minimum and maximum return and supply temps for cogen, chilled water,
            // and condenser water loops
            // declare acceptable ranges from the minimum and maximum

            if(Timer % 60seconds = 0)  {       // do these tasks every 1 minute

                  ConstructAbsChillerObject();
                  if(AbsChillerObject.CogenSupply water >maximum °F   {
                                 Control Output: Open Balance Radiator valve;
                                 Control Output: Adjust VFD fan speed to lower cogeneration
                  water to minimum;
                                 }
                  if(AbsChillerObject.CondenserWaterReturnTemp >maximum °F  {
                                 Control Output: Close cooling tower water bypass valve;
                   if(AbsChillerObject.CoolingTowerBypassValvePct == 100%)
                                         Control output: Increase VFD to reduce supply water temp;
                  }
                        if(AbsChillerObject.ChilledWaterReturnTemp <minimum°F)
                        Control output: Open Absorption Chiller bypass;
                } // end Timer loop
        }  // end AbsChillerModulation()
```

```

ICEStart()  {      // Begin ICEStart()
        Control Output: Start ICE
        if (ICE is running), continue
        else Alarm();
        Output: Request ICE-1 Kilowatt output from PM Generator Meter
        Input: Return ICE-1 Kilowatt output from PM Generator Meter
        if(ICE-1 Kilowatt output >20 kW),
              Return 0;               // Return OK
              else Return –1;         // Return error
 }  // end ICEStart()

      ICEDiagnostic(ICEStatusFlag)   {          // begin ICEDiagnostic
            Output: Request current oil pressure
            Input: Return current oil pressure
            if(oil pressure <10% of normal operating pressure for more than 1 second) {
                    ICEStop();
                    return –1;
                  }
                  if(oil pressure >110 psi for 10 seconds)
                          Alarm();
             Output: Request Combustion air temp
             Input: Return Combustion air temp
             if(Combustion air temp >130°F for ≥10 seconds )  {
                    ICEStop();
                    return –1;
                  }
             Output: Request Kilowatt output
             Input: Return Kilowatt output
             if(Kilowatt total output <160 or >220 for ≥ 10 seconds)
                          Alarm();
             if(Kilowatt total output <140 for ≥ 10 seconds )  {
                    ICEStop();
             return –1;
                  }
             Output: Request Generator Voltage Phase A
             Input: Return Generator Voltage Phase A
             Output: Request Generator Voltage Phase B
             Input: Return Generator Voltage Phase B
             Output: Request Generator Voltage Phase C
             Input: Return Generator Voltage Phase C
             Output: Request Generator Amps Phase A
             Input: Return Generator Amps Phase A
             Output: Request Generator Amps Phase B
             Input: Return Generator Amps Phase B
             Output: Request Generator Amps Phase C
```

```
                Input: Return Generator Amps Phase C
                if(Generator Voltage Phase A <250 or >310 for ≥ 1 second )  {
                        ICEStop();
                        return –1;
                      }
                if(Generator Voltage Phase B <250 or >310 for ≥ 1 second )   {
                        ICEStop();
                        return –1;
                      }
                if(Generator Voltage Phase C <250 or >310 for ≥ 1 second )   {
                        ICEStop();
                        return –1;
                      }
                if(Generator Amps Phase A <0 or >350 for ≥ 1 second )   {
                        ICEStop();
                        return –1;
                      }
                if(Generator Amps Phase B <0 or >350 for ≥ 1 second )   {
                        ICEStop();
                        return –1;
                      }
                if(Generator Amps Phase C <0 or >350 for ≥1 second )   {
                        ICEStop();
                        return –1;
                      }
                Output: Request Generator Frequency
                Input: Return Generator Frequency
                if(Generator Frequency <59.5 or >60.5 for ≥ 1 second )   {
                        ICEStop();
                      return –1;
                      }
        }    // end ICEDiagnostic()
    }  // end main()
```

4.4 Conclusions

At the outset, seven issues that were suspect in revenue loss were identified:

- Static On/Off Modified Dispatch
- Controller granularity
- Interoperability
- Heat rate
- Thermal capture
- Auxiliary load
- Inrush current.

Although the economic impact of these issues has not yet been quantified, how they were affecting field operations has been outlined. Based on these data and analyses, it is possible to outline next steps.

1. An economic analysis of financial impact of three types of dispatch should be completed. Based on this potential cost savings, RE should research and pursue cost-effective options for dynamic control, i.e., control that can run the generators based not on the clock but on actual operating conditions.

2. At the same time that RE is assessing dynamic control, it should improve controller granularity. Now, in essence, there is no granularity because a time clock is set once based on the minimum "bucket-size," i.e., building load. We have shown that this approach leads to lost revenue, incidental export, or both. Once the controller can be changed automatically, dynamically, it will be desirable to be able to make very fine adjustments from 0 kW to 220 kW.

3. Interoperability is the one issue that RE has addressed, so it does not stand as an operational or economic barrier to project profitability. However, even though RE has solved the problem for its existing sites, it is desirable for RE and the industry to have communications standards and open systems that will allow maximum interoperability at least cost in the future.

4. It will be unwise to use the whole generator range without having a very accurate heat rate curve. Without it, dispatch control will not know what the lower limit is of profitability (i.e., the Throttle-Down Threshold) for any given facility on any given day. RE needs to have excellent heat rate data. When that information is gathered, Throttle-Down Thresholds may be calculated dynamically at whatever time interval is appropriate.

5. The thermal data show a very interesting situation: the field unit can produce 97% of manufacturer-stated thermal output (at least), but it only produced this output twice in almost 3 months. It is possible that, because the data were for winter, the cooling load was handled almost entirely by the economizers and only required half-output from the absorption chiller. That flies in the face of cooling load data from the building, however. (See, for example, Figure 2.2.2-1, which shows that cooling loads vary less than 20%

between the hottest and coolest months.) The average thermal capture is only 59%. Something may be wrong with the way the system is being operated. The absorption chiller should serve as chiller base load for the building, but it is not currently being dispatched that way. This requires further follow-up, analysis, and solution.

6. No RE auxiliary loads have VFDs on them at present, so it is certain that they are wasting electricity. Paybacks will vary by site, but VFDs are likely a cost-effective solution. Quantitative analysis remains to be done.

7. Inrush current analysis should be easy and should tell quickly whether the customers are being billed in any instances for kilowatts drawn by induction motors at start-up. Solutions include possible control devices to reduce inrush spikes or the use of synchronous generators.

Task 5: Install and Test Energy Management Software

5.1 Introduction

The primary concern of RE in building its test platform was that the system must provide precise and consistent data under actual operating conditions. Many of the systems described in this report were installed at actual operating RE sites. The systems were tested according to two categories of criteria:

- Technical criteria
  - Platform device capabilities
    System must have precision; quantity and diversity of outputs; compatibility with building EMSs — including legacy systems, existing systems, and future systems; availability of device drivers; software/hardware integration and interoperability; enterprise-wide solution capability; and Internet deliverability.
  - Compatibility with proposed installation environments
    System must have the ability to operate at extremes of temperature and humidity, device durability, remote operation, and low maintenance.
  - System must use industry-accepted non-proprietary communications protocols to encourage vendor participation in future development.

- Business criteria
  - Data ownership
    RE must be able to transmit, own, and archive data from its own projects.
  - Initial cost
    The device first cost must meet RE's internal cost criteria.
  - Recurring cost structure model
    Once purchased, the device should have no lingering service costs or recurring costs.
  - After-sale engineering
    RE required excellent after-sale support for installation and customization to serve its evolving site-specific and enterprise-wide needs.
  - Flexibility
    RE is a technology-agnostic organization, which specifies and installs the best technology for the application. Additionally, RE’s future designs incorporate hybrid or multiple technology installations.
  - The control platform must be versatile enough to support any and all configurations.

In all, RE tested and/or evaluated platforms from nine vendors: Silicon Energy, eLutions, Enflex, Envenergy, DTE/CoActive Networks, Eutech Energy | now, MTC Webfoot, ABB, and Power Measurement Limited (PML). The only platform that met all of RE's criteria was PML. The ION 7500 is now installed in all RE sites, with the exception of two early sites in which the PML model ION 7350 is installed. The ION 7500 is the only platform that RE currently deploys in new installations.

5.2 Platform Testing

The market for distributed generation (DG) is relatively new, and there has been no consensus about what the information needs of DG developers and users are. The variations among offerings are large. Most products are new and untested. Each of the platforms examined offered a unique set of features and benefits. These facts increased the time RE had to spend testing and evaluating platforms before it found one that was acceptable. RE's business criteria evolved as it came to understand the product offerings and how they were priced. Its primary technical criteria did not change: RE had to have precision information from a device that could deliver under the environmentally rugged conditions encountered on building rooftops, in basements, and in the variety of other conditions where its generators were installed.

5.2.1 Silicon Energy

When RE was formed, it planned to deliver energy information to its clients as a primary service. Silicon Energy (SiE) was the company selected to provide the energy information software capabilities to fulfill RE's mission. SiE was formed by core IT engineers from the dissolution of PG&E Energy Services. It was an original subcontractor to deliver the DEIS test platform. The SiE team built a very impressive software suite for enterprise energy management. It appeared from the literature and simulated, nonfunctional demonstrations that there were few monitoring or control tasks the software could not handle. RE believed the software could fulfill all requirements of ICMMBAC (see Task 1, Section 4) for its enterprise.

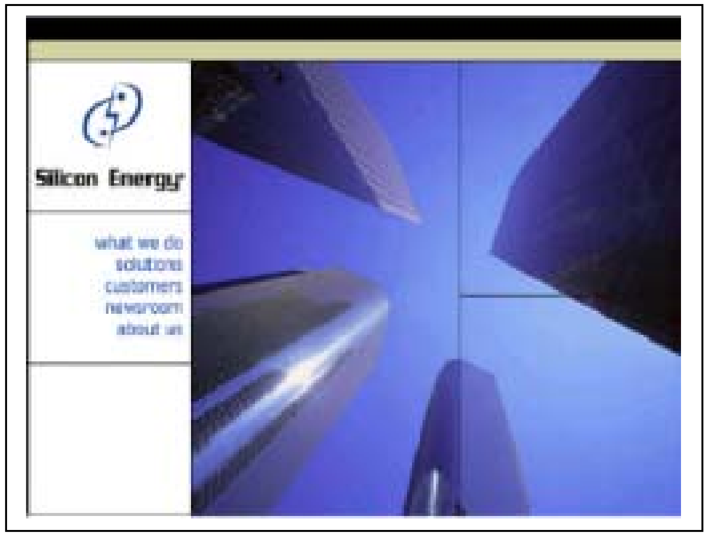


Figure 5.2.1-1: The Silicon Energy look

When RE rolled out the system into seven target buildings, the results were mixed. Four of the buildings used Siemens Apogee EMSs. It was difficult to get the software to recognize the points of the hardware. The team of SiE and RE engineers worked around the issue by developing a virtual software point for each real hardware point. SiE engineers did eventually resolve the need for Siemens EMS drivers.

Figure 5.2.1-2: The Silicon Energy graphical user interface

RE decided that it should test the system in buildings with non-Siemens controllers to see what integration would be possible. The SiE software was installed in two buildings with Andover AC256 EMS systems and in one with a Honeywell XBSI Controls EMS.

The issue of drivers for these EMSs became more problematic and appeared to be a serious stumbling block to the planned high-paced rollout. One hundred eighty points were installed in the seven buildings. The mixed results from these projects made it apparent that it would be necessary to install other gateway hardware to collect the building and new cogeneration system information. RE began purchasing and evaluating other hardware offerings to integrate with the SiE software. Understandably, though, the software maker was reluctant to accept new hardware technologies (some provided by competitors) because it is time-consuming to write software for new hardware and the market for the hardware device may be limited. The software maker stated it would sometimes need weeks or months to test devices prior to committing to integration. This delay, added to the time spent finding hardware, extended the time required to install projects and impacted RE's aggressive deployment schedule.

Figure 5.2.1-3: The gateway device (a PC) with stand

The SiE platform met some of the technical and business criteria. Because it was a software system, it was capable of modeling any quantity and diversity of outputs. It offered enterprise-wide solution capability and Internet deliverability. Once RE purchased the points, it could own its own data.

The SiE platform did not meet other RE platform testing requirements. The platform device's precision depended completely on the hardware precision; hardware was not specified nor was any particular vendor endorsed as a qualified provider, so the precision could not be relied on in any given installation.

No solution was found for the absence of the difficult-to-find device drivers. Integration of software and hardware was an unsolved problem that prevented interoperability. The prescribed SiE gateway was a personal computer (PC) running Microsoft Windows NT 4.0. But PCs operate poorly in extremes of temperature. Many of the RE installations are on building rooftops or in parking garages, exposed to wind, rain, extreme heat, cold, and ultraviolet light. Also, PCs require frequent rebooting, which makes remote operation extremely difficult and requires high maintenance.

Hundreds of PCs installed in relatively inaccessible remote locations was not a realistic *scalable* business platform. RE's search for hardware to integrate with this software was time-consuming and ultimately unsuccessful, but it was pursued with great *care* and *diligence*. RE had a significant investment of time and money in the success of this program and was not quick to discount or dismiss this offering. Additionally, the system had some recurring costs that did not meet RE's model. Engineering service after the sale was expensive and not always timely.

- Technical and business requirements met:
    - Capable of modeling any quantity and diversity of outputs
    - Enterprise-wide solution capability
    - Highly advanced graphical user interface (GUI)
    - Internet deliverability
    - Data ownership

- Technical and business requirements unmet:
    - Remote system control capability
    - Billing solution
    - Compatibility with proposed installation environments
    - Compatibility with many building EMSs
    - Software/hardware integration and interoperability
    - Complete solution
    - Remote operation
    - Low maintenance
    - Low first cost
    - No lingering service costs or recurring costs
    - Timely and affordable after-sale engineering

5.2.2 eLutions

Concurrent with the testing of the first platform, many other vendors were evaluated and deployed. One of the most promising alternatives was eLutions. The company is part of the Invensys/Engage company network. The product offered a Web-based front end, giving immediate integration with the Internet. The company had also developed SCADA hardware used by many OEMs.

Figure 5.2.2-1: The eLutions controller

After the learning experience from the previous platform, the importance of hardware/software integration was a firmly established criterion. This offering favorably impressed RE. eLutions was immediately placed in one of RE’s sites for evaluation. After approximately 12 weeks of trials, the data coming from the beta site were still more than 8% off when compared with the utility meter on the main electrical service. Considering the stringent accuracy requirements of the DEIS, this was not acceptable. When this result was presented to the vendor, it was not able to rectify the problem in a timely manner and therefore did not satisfy the technical agenda. These inaccuracies were addressed by altering calculations in the devices. This left many questions as to the validity of the data and RE's clients' perceptions of the measurements.

Technical deficiencies aside, eLutions had a business model that did not meet RE's business requirements. All deployed equipment was property of eLutions. All data was owned, transmitted, and stored in eLutions' data center in Florida. RE would be issued password access to eLutions' Web site. Broadband communications was the only option offered. RE data would be available for other eLutions clients' viewing. The vendor promised that the data would be "generically labeled," but it did not change its intention to use the data to solicit business. A per-site installation fee was to be negotiated. A monthly fee per-point-installed was to be negotiated.

- Technical and business requirements met:
    - Capable of modeling any quantity and diversity of outputs
    - Compatibility with proposed installation environments
    - Advanced GUI offering interactive charting to create "What If" scenarios
    - Compatibility with building EMSs
    - Software/hardware integration and interoperability
    - Enterprise-wide solution capability
    - Internet deliverability
    - Low maintenance

- Technical and business requirements unmet:
    - Precise billing solution
    - Data ownership
    - Integrity of information developed
    - Remote system control capability
    - Device durability
    - Capable of precision
    - Low first cost
    - Long term, multi-site contract structure
    - No lingering service costs or recurring costs
    - Timely and affordable after-sale engineering

5.2.3 Enflex

Enflex was another top contender during this process. Founded by former SiE engineers, it understood the specific challenges that RE was facing. The company had manufactured hardware to fill the hardware gap SiE customers were facing. But there was no supporting software, leaving it reliant on enterprise software products such as SiE's for its success. There was little cooperation between Enflex, the hardware provider, and SiE, the software provider. The software company did not want to validate Enflex's MG200 as an acceptable device. RE was left to

Figure 5.2.3-1: The Enflex Controller

do the integration with little support. The results were less than satisfactory.

Ultimately, the success or failure of the device was judged on merits. RE put politics aside and made the device work. Integration was successfully completed. However, the output did not match data coming from the building EMS, so RE was not confident in the output. The device was expensive and was useful for general building analysis only. It needed SiE software to be useful.

Figure 5.2.3-2: First RE installation

- Technical and business requirements met:
    - Compatibility with proposed installation environments
    - Data ownership
    - Low maintenance
    - Remote operation
    - No lingering service costs or recurring costs.
    - Ability to operate at extremes of temperature and humidity

- Technical and business requirements unmet:
    - Control and billing criteria
    - Compatibility with diverse set of building EMSs
    - Internet deliverability
    - Software/hardware integration and interoperability
    - Capable of precision
    - Low first cost
    - Timely and affordable after-sale engineering
    - Capable of modeling any quantity and diversity of outputs
    - Enterprise-wide solution capability

5.2.4 Envenergy

Promoted as the "ultimate" solution to the technical and business requirements of distributed power, the Envenergy device had great promise. By this time, word was out that RE was dissatisfied with available technologies.

The physical device brought to RE offices for demonstration was a prototype and the only one in existence. It included multiple communications ports, including Ethernet, modem, serial, RS485, and fiber optic. The device was compact and appeared to be able to do exactly what RE needed. As with all its predecessors, a site was chosen, and the Envenergy product was immediately deployed.

Figure 5.2.4-1: The Envenergy installation

Integration was successfully completed. But results, compared against the utility meter on the utility main, were marginal at best. Ultimately, only five points of information were configured, two of which were temperatures (room and inside MPX box). The device was very expensive and not commercially available. It was incapable of calling the Internet because it had no PPPOE Client; therefore, it had to call out directly over phone lines to the Envenergy server in Santa Barbara, California. During the first month of testing, more than $1,800 in long distance charges were accrued. Envenergy used the Per Point/Per Month Model. Envenergy owned all devices, and data was stored at its facility in Santa Barbara. This device also needed SiE software to be useful.

Figure 5.2.4-2: The Envenergy controller

- Technical and business requirements met:
  - Compatibility with proposed installation environments
  - Low maintenance
  - Remote operation
  - Ability to operate at extremes of temperature and humidity
  - Device durability

- Technical and business requirements unmet:
  - Control and billing criteria
  - Compatibility with building EMSs
  - Internet deliverability
  - Software/hardware integration and interoperability
  - Capable of precision
  - Low first cost
  - Capable of modeling any quantity and diversity of outputs
  - Enterprise-wide solution capability
  - Commercial availability
  - Data ownership
  - No lingering service costs or recurring costs

5.2.5 Other Device Platforms

Four other device platforms were evaluated before RE found its choice platform. By this time, RE had become expert at recognizing which solutions would work and which would not. For example, it became clear that if the platform was hardware only, RE could not use the device or it would face the same integration issues it had already encountered. This was the case with Co-Active Networks and MTC Webfoot. The Eutech Energy | now product claimed that billing was a part of the package. However, to do accurate billing, an independent meter/datalogger must be connected to the main electrical service to calculate demand. Eutech did not offer any independent meter, so the product raised doubts about its billing accuracy. The ABB solution offered a precision device, but the software was limited to support of one site. It was incapable of enterprise-wide control and monitoring.

5.2.6 Power Measurement

PML differed from the foregoing platforms in its ability to fulfill RE's requirements. PML offers a commercially available precision device for purchase at a reasonable price. Once RE purchased the device, it could own and house its own data, no strings attached. PML devices were originally made for use in Canada, and they are operable, the company says, down to -20°F. The housing is rugged and robust and extremely compact.

Figure 5.2.6-1: The Power Measurement look

PML offers a generic enterprise software that RE customized to run multiple distributed power sites. The platform has a Web-based front end and is remotely operable. The company provides engineering support after the sale to handle the integration of the system with building EMSs. And the system captures an extremely diverse set of information about system operations.

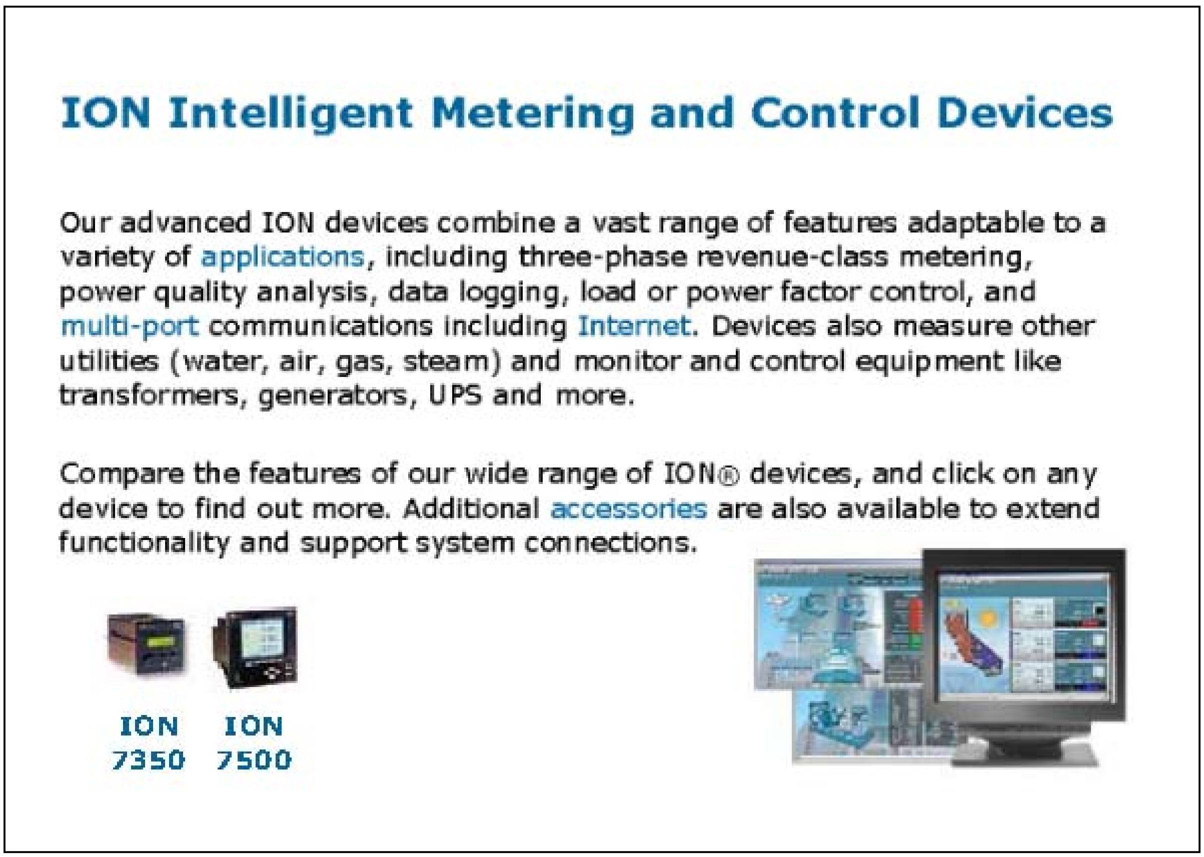


Figure 5.2.6-2: Power Measurement products selected by RealEnergy (3/31/02)

- Technical and business requirements met:
    - Compatibility with proposed installation environments
    - Clear understanding of precision power measurement

- Provides billing-ready data and conversion software
- Ability to adapt to constantly evolving requirements
- Multiple simultaneous communications ports
- Industry standard Modbus RTU communications protocol
- Low maintenance
- Remote operation
- Ability to operate at extremes of temperature and humidity
- Device durability
- Compatibility with building EMSs
- Internet deliverability
- Software/hardware integration and interoperability
- Unlimited scalability
- Capable of modeling any quantity and diversity of outputs
- Enterprise-wide solution capability
- Commercial availability
- Data ownership
- No lingering service costs or recurring costs

- Technical and Business Requirements Unmet

  - None

5.3 Conclusion

The DEIS is built around the PML platform. Outputs from the system (see 1.4.3) are used by RE for all billing, historical analysis, and operational functions. Inputs can be accommodated by PML easily and used for optimal dispatch and control (see Task 2, all). The PML system is relatively inexpensive, flexible, configurable, and capable of running the RE generator fleet from a single point of control. RE has deployed the system in all 13 of its operating sites to integrate, communicate, monitor, meter, bill, send alarms, and control its generators, including ICEs, absorption chillers, large PV arrays, and microturbines. As data have accumulated, the PML platform has continued to show its capabilities. The after-sale engineering support has been excellent.

The market for distributed power is very new, and most of the products reviewed by RE were either still in the beta phase or no more than a year or two old and without substantial commercial operating histories. As the small generation market ripens, these products will improve. It is likely they have already improved a great deal. RE continues to re-evaluate its platform of choice and to test it against other reference systems. It is quite possible that products from companies whose services were previously declined could displace PML as the platform of choice should they prove that their products provide greater precision along with the other capabilities RE requires.

RE is striving to create a control system in which *all* of the integral parts are interchangeable and several vendors are available to supply each point. This will encourage evolution and competition while creating a *commercially available DG centralized command and control system*. Such a system does not exist today.

Task 6: Contractual and Regulatory Issues

6.1 Introduction

6.1.1 California and Distributed Generation – A Brief Overview

Aside from the construction and operational hurdles before any DG project in California, a raft of other issues must be addressed, or at least acknowledged, by the DG developer.

From a macro perspective, California's entire energy sector has been in a state of regulatory and business uncertainty for nearly 2 years. The DG market has not been exempt from this turmoil. Despite attempts by the legislature, the governor, the California Energy Commission (CEC), and the CPUC to address some of the hurdles facing the DG market, post AB 1890, the situation still remains largely unresolved. Areas of progress, such as the passage of SB 28X and the efforts to homogenize interconnection policies across the three investor-owned utilities, have been slow to fruition and more than offset by other unsettling issues. Along with the potential end of net metering for solar power, the entire DG market faces punitive standby rates filed by the utilities and also a departing-load charge rate case at the CPUC that would ruin the economics of any system's operation. With all of this in mind, businesses must decide whether to install DG systems on site.

From a micro perspective, the installation of a DG system requires an investment of both time and finances to meet all of the regulatory and business transaction costs associated with construction and operation. This section will focus almost entirely on these issues. Specifically, this section will follow each of the associated transaction costs.

Table 6.1.1-1: RealEnergy Project Stages

Project Stage 1	Project Stage 2	Project Stage 3
Contractual Negotiations (Business)	Authority to Construct Permit (Regulatory – Regional) Building Permit (Regulatory – Municipal) Design, Site Prep, and Construction Issues (Regulatory and Business – Municipal) Interconnection Application (Regulatory – Regional) Interconnection Agreement (Business)	Building Shutdown (Business) Building and Safety Sign-off (Regulatory – Municipal) Final Interconnection Inspection (Regulatory – Regional) Permit to Operate (Regulatory – Regional)

Project Stage 1, Project Stage 2, and Project Stage 3 will be described in detail in sections 6.2, 6.3, and 6.4 of this report.

6.1.2 RealEnergy's Business Model and Distribution System Design

RE installs, owns, and operates clean DG technology to serve its clients' on-site load. RE clients are concentrated in the class "A" commercial real estate market. RE is financially obligated to ensure each system's optimal operation because of the 15-year energy service contract signed between RE and the client. RE is flexible enough to design its systems around a host of constraints. RE's DG/CHP systems have been installed on rooftops, garages, or unused interstitial space within clients' buildings.

RE has completed the installation of nearly 4.6 MW of CHP and non-CHP DG projects. (See Table 6.1.2-1 below.) The projects are located in 13 commercial properties.

- Three are PV projects (330 kW).
- Nine are IC engine projects (4.2 MW).
- One is a microturbine project (60 kW).

Total capacity among the various systems ranges from 60 kW to 1,000 kW. The 13 projects are dispersed across three utility territories. (Please see Figure 6.1.2-1 below.)

To date, RE has deployed four types of systems:

1. Solar (three projects – 330 kW)
2. Microturbine (one project – 60 kW)
3. IC with CHP (four projects – 2.4 MW)
4. IC without CHP (five projects – 1.4 MW)

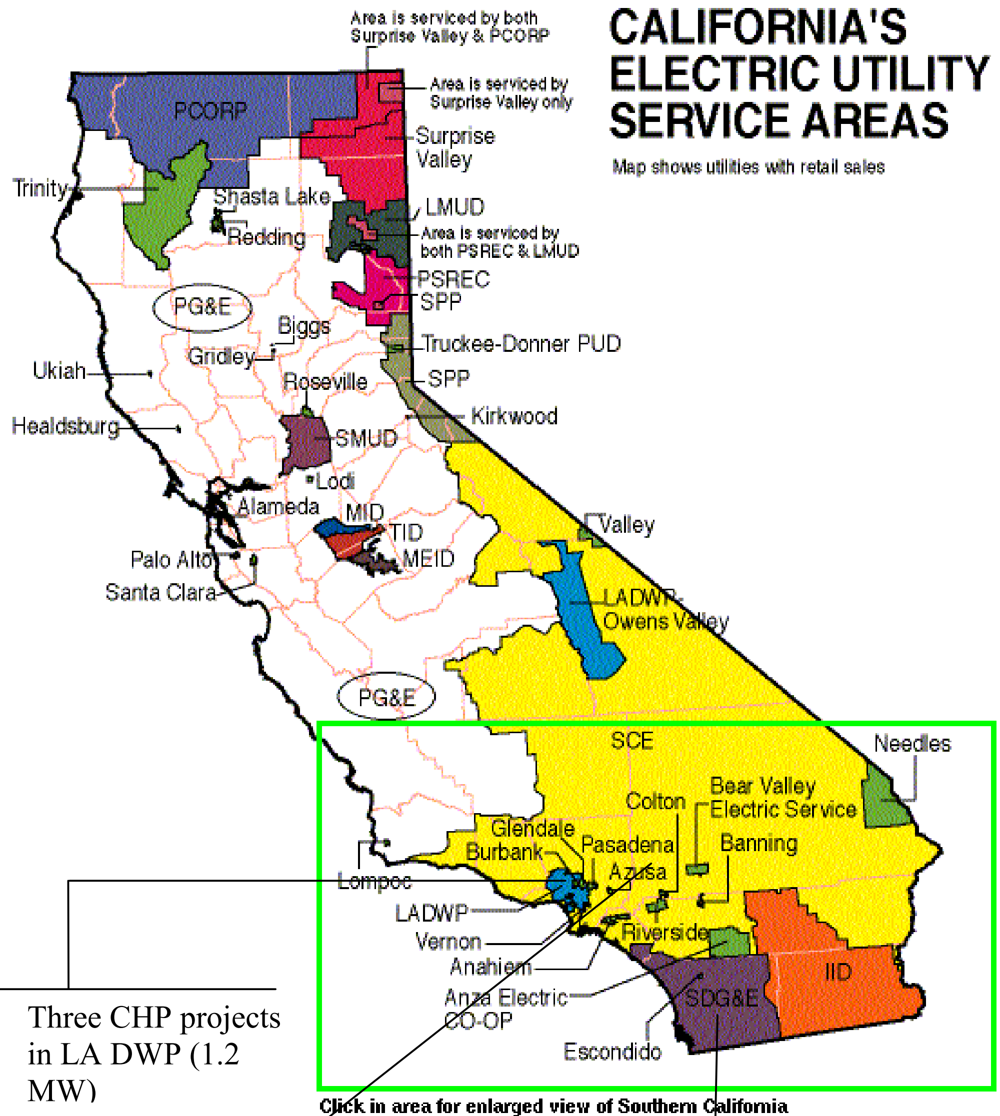
RE's IC systems use the Hess 220 cogeneration units. RE determined these cogenerators to be the best currently on the market because they are clean, fuel-efficient, and scalable. Total site generation capacity ranges from 200 kW (one engine) to 1,000 kW (five engines). All of RE's IC power plants use natural gas as the fuel source.

For projects also deploying CHP technologies, RE used Century absorption chillers and/or Alfa Laval heat exchangers, depending on the site's thermal demand. RE quickly learned the advantages of going with a standardized but scalable technology offering as no two sites would be the same but cost-saving experience could be built up within the staff of RE's construction team.

Table 6.1.2-1: Matrix of RealEnergy Projects
(As of 3-31-2002)

Initial Analysis and Proposal

Project Name	Type	Size (kW)	Utility Territory	Tariff Rate	Status	IC Type
Carlsbad	Solar	110	SDG&E	A	Operating	"Net Metered"
Fountain Valley 17390	Solar	110	SCE	TOU8	Operating	Non-Export
Fountain Valley 17330	Solar	110	SCE	GS2	Operating	Non-Export
IBT	IC	600	SDG&E	ALTOU	Operating	Non-Export
Centerside 1	IC	400	SDG&E	ALTOU	Operating	Non-Export
Sky Park	IC	400	SDG&E	ALTOU	Commissioning	Non-Export
Genesse	IC	400	SDG&E	ALTOU	Commissioning	Non-Export
Oceangate	IC	400	SCE	TOU-8	Operating	Non-Export
Two Town Center	IC	1000	SCE	TOU-8	Commissioning	Non-Export
Boatyard	Micro-turbine	60	SCE	GS2	Operating	Non-Export
West Century	IC	400	LAWPD	S3	Operating	Non-Export
World Savings	IC	200	LAWPD	A3A	Operating	Non-Export
Lankershim	IC	400	LAWPD	S3	On-Hold	Non-Export



- Three CHP projects in LA DWP (1.2 MW)

- Three CHP projects in SCE territory (1.46 MW)
- Two solar projects in SCE territory (220 kW)

- Four CHP projects in San Diego (1.8 MW)
- One solar project in Carlsbad (110 kW)

Figure 6.1.2-1: RealEnergy's operating projects in California
(As of 3/31/02)

6.2 Project Stage 1

Contractual Negotiations

Because of the long-term nature of RE's business model, the nature of the installations, and the types of clients RE works with, sizeable time and expenses must be expended in addressing "up front" issues.

Each of RE's contract negotiations took at least 3 months to complete. For one of RE's more complicated projects, it took more than 195 days to finalize the contract with the client. On average, RE's contract negotiations took approximately 116 days.

The completion and signing of RE's first group of contracts, with Arden Realty[33], consumed more than 4 months, pushing back the start date of many projects by several months. Both RE and its client/investor were committed to making a "boilerplate contract" that could be used in the future across various projects, both with Arden and other commercial real estate firms.

In some cases, the signing of the contract with the client became contingent on approval of the final system design. For RE, this raised the specter not only of the opportunity costs of time spent negotiating a failed contract but also of hiring an engineering firm to draw up an initial design based on extensive on-site walkthroughs, only to have the project scrapped. However, this only happened once.

6.3 Project Stage 2

6.3.1 Authority to Construct Permit (Regulatory – Regional)

To begin construction on a non-solar DG/CHP project, it is absolutely crucial that two permits be obtained: the building permits from the municipal building and safety department and the authority to construct (ATC) from the regional air quality control district (air district). The air districts governing the construction of RE's projects were the South Coast Air Quality Management District and the San Diego Air Pollution Control District.

The job of the local air quality district is to protect and improve the air quality of a given region. To accomplish this task, these districts regulate the emissions from a host of technologies. For all new stationary sources emitting pollution, the local air quality district attempts to assess the technology's impact on both local and regional air quality. To accomplish this, every air district in California is given enforcement powers. The ATC is an extension of this. As the name implies, without this permit from the regional air district, no type of stationary resource can begin construction.

The ATC application allows the air district to assess a stationary source's ability to comply with the districts' strict emissions guidelines. Applications also entail the crafting of precise models determining any immediate air quality impacts.

---

[33] Referred to by RE as "Arden Phase 1" because it was the first 7 of an eventual 11 projects to be completed by RE for Arden Realty.

RE only needed to submit nine applications. The solar projects are non-polluting, and the microturbine project, at only 60 kW, is considered too small to warrant a permit.

RE discovered that with its standardized DG/CHP package, once both air districts had approved the first installation, obtaining the ATC for later projects was far easier. As the air district staff became familiar with RE's application package and the RE staff improved the quality of its submissions from lessons learned, the time to receive an ATC permit dropped. For RE, the time to receive an ATC permit ranged from 7 days to 59 days, with an average of approximately 27 days.

The cost of applying for an ATC permit, however, remained fixed. Based mostly on the kilowatt size of the system, the ATC permit cost ranged from $1,675.33 to $5,310.30.[34]

Because an ATC permit is absolutely crucial to beginning construction, RE made a business decision to begin filing them before the contract negotiations closed. Again, this only proved to be a problem one time, when the project was cancelled for financial reasons during the contract negotiations. In this case, the money spent obtaining the ATC from the local air district could not be recovered.

The air impact modeling has several wrinkles built into it that can slow down the process of obtaining of an ATC permit. Most notably, if a school is within 100 feet of the installed cogeneration system, all of the air quality districts require that a notification be sent by the air district (not the applicant) to all of the guardians of the children attending the impacted school. Following that, there is a 30-day comment period whereby the guardians may challenge the issuance of the ATC. A challenge can cause delays for further testing or stop the project all together. This process only affected two of RE's nine projects needing ATC permits and never delayed their start-up by more than 30 days.

[34] For the AQMD, the fee an applicant pays to process an ATC permit request is an estimate, based on established guidelines. If the amount of time spent by the district on processing a successful permit is less than the estimate, a "reconciliation" can be filed that refunds the applicant the difference.

Figure 6.3.1-1: California air quality districts and RealEnergy projects
(As of 12-31-01)

6.3.2 Design, Site Prep, and Construction Issues (Business)

6.3.2.1 Design

Project design begins prior to receiving the ATC permit. The design process can take substantial time, as three groups must approve it prior to submitting it for municipal plan check.

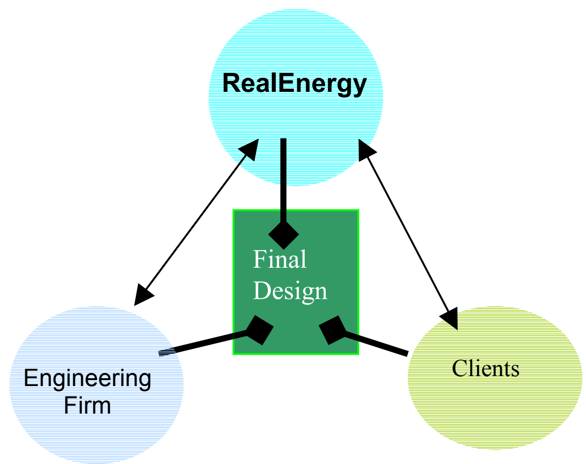


Figure 6.3.2-1: Project design approvals

Typically, this process takes about 2 full months. The site must be toured. A load analysis must be conducted to assess the host site's demand and to properly size the system for optimal, long-term economic performance.

6.3.2.2 Piping

Each of RE's projects faced major piping issues, either with establishing a gas service, running long conduit to connect the RE system to the building's switchgear and meters, or tying into the building's chilled water system. Rooftop installations, while "clean" in some respects, pose especially difficult problems concerning establishing gas service. In one case, RE had to run more than 800 feet of natural gas pipeline up 11 stories to establish service with the generators on the rooftop of the building. In another, it had to lay an electrical conduit run that extended through a parking lot, cored through a parking structure, and then went underneath the building to reach the point of common coupling.

6.3.2.3 Gas Supply

Not all buildings had gas service prior to construction. In fact, one-third of all RE cogeneration projects required that gas service be added on site.[35] This can add substantially to total project costs, as a pipe must be run off the gas company's main line and a gas vault and a new gas meter must be installed. From that point, a gas line must still be run on the customer's property to the cogeneration units. Furthermore, existing gas service on site is no guarantee of substantial cost savings. First, gas usage cannot be sub-metered off of established service lines. Any new and independent use of gas on site requires, at least, the installation of a separate gas meter. The

[35] This is not surprising. In the California economy, the commercial sector (encompassing commercial real estate) has the least amount of diversification in its energy usage, relying heavily on electricity to meet its overall energy needs.

installation of this gas meter may also be problematic if the existing equipment does not have the "T" valve from which to install the new meter.

Without the "T" valve, tying into the existing gas service lines on site is problematic. A separate gas line and gas vault for RE's system must be installed on the utility side of the line, further adding to installation costs.

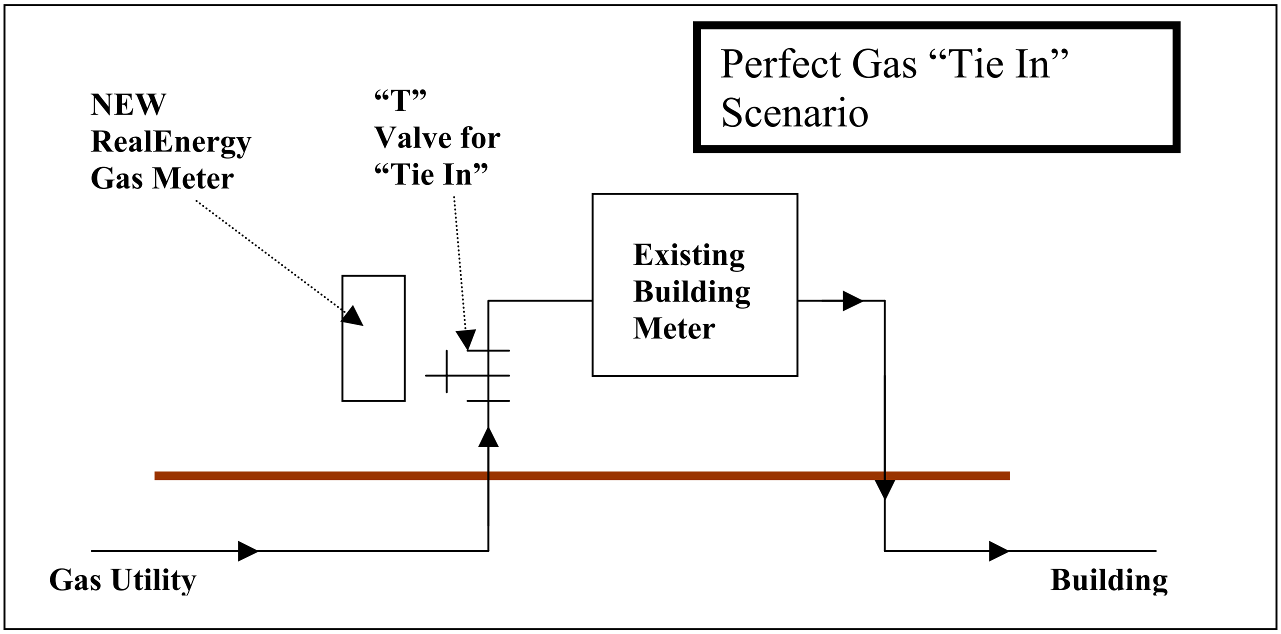


Figure 6.3.2-2: Project design

6.3.2.4 Construction

Construction begins once the ATC and building permits (explained below) are secured. RE employed three lead contractors to construct its nine permitted projects.

RE's COO and vice president of construction work with four RE project managers to oversee the construction process. RE's active role in the construction process ensures that the projects are built according to design and on budget.

Construction cycles have been decreasing as more projects are built. Although the first projects took more than 5 months to construct, later projects were being completed and commissioned in less than 4 months.

6.3.3 Building Permit (Regulatory – Municipal)

To receive an approved plan and a municipal permit to construct, the municipal plan check must be complete. Unlike the ATC permit process, however, the plan check approval and building permit process cannot begin prior to the completion of the design process. RE and its lead contractor must first finalize design plans with the client and an independent structural engineer before submitting the plan to the local building and safety department.

Although it was relatively easy to receive approval for the solar systems, for RE's DG/CHP systems it was not. RE's 13 systems were located in seven municipalities, with each building and safety department raising different issues for RE to address. Municipal plan check took anywhere from 14 to 56 business days to complete.

Specific issues that were raised by the municipalities before approving RE projects included:

- The method of safely tapping into the main switchgear on site and interconnection in general
- The requirement that all major equipment to be UL rated
- The reclassification of "building occupancy" for garages because of system size. This required that a firewall be created to enclose the system
- Concerns over extended natural gas line runs.

Overall, two themes emerged as each application was processed: (1) a general lack of experienced plan check staff in reviewing DG projects and (2) unfamiliarity with the protection and system requirement standards called for by Rule 21. A synergy and obvious overlap exist between some of the work performed by utility protection engineers in reviewing interconnection applications (e.g., Rule 21) and municipal plan check personnel in assessing system safety.

Municipalities' lack of awareness of the existing interconnection requirements under Rule 21 led to quantifiable delays in plan check approval. The city of Long Beach took more than 6 weeks to complete its review, as it was unsure of the safety provided by the protection devices — devices called for and installed according to Rule 21.

6.3.4 Interconnections and RealEnergy – An Introduction

RE only supplies a portion of the host site's total electricity demand, so its systems are designed to run in parallel with the local utility grid. To accomplish this, RE must be approved to interconnect at the building's PCC with the local grid. Receiving an approved interconnection is a two-step process. First (except in Los Angeles Department of Water and Power territory), an interconnection application must be approved by the local utility, and then an interconnection agreement must be signed.

The interconnection application is entirely technical, with its requirements shaped by California's Rule 21.[36] The utility and the energy producer must also enter into an interconnection agreement. The agreement sets forth the contractual conditions by which the DG can legally operate. Across all California investor-owned utilities, four types of interconnection agreements exist: [37]

- Net metering
- Non-export
- Inadvertent export
- Power production agreement.

---

[36] Rule 21 requirements apply only to investor-owned utilities and not municipal utilities. Some municipal utilities, however, including LADWP, SMUD, and the City of Riverside, are adopting rules based on Rule 21.
[37] Those wishing to simply remove themselves from the grid do not need to file anything.

RE must secure both an approved interconnection application and a signed interconnection agreement prior to operation. The processes for acquiring these documents are very different. Success in obtaining one of the two documents does not guarantee receipt of the other. The following sections explain documents, their processes, and RE's experience in much greater detail.

6.3.5 Interconnection Application (Regulatory – Regional)

The interconnection application is the technical document describing exactly how the proposed system will interconnect with the local utility grid. Through the Rule 21 working group, the process has been both simplified and standardized, although much work is still needed.

Each application requires the submission of four "drawings" and one photograph:

- Site plan
- Single line diagram
- Electrical floor plan
- AC/DC elementary diagram or protection drawing.

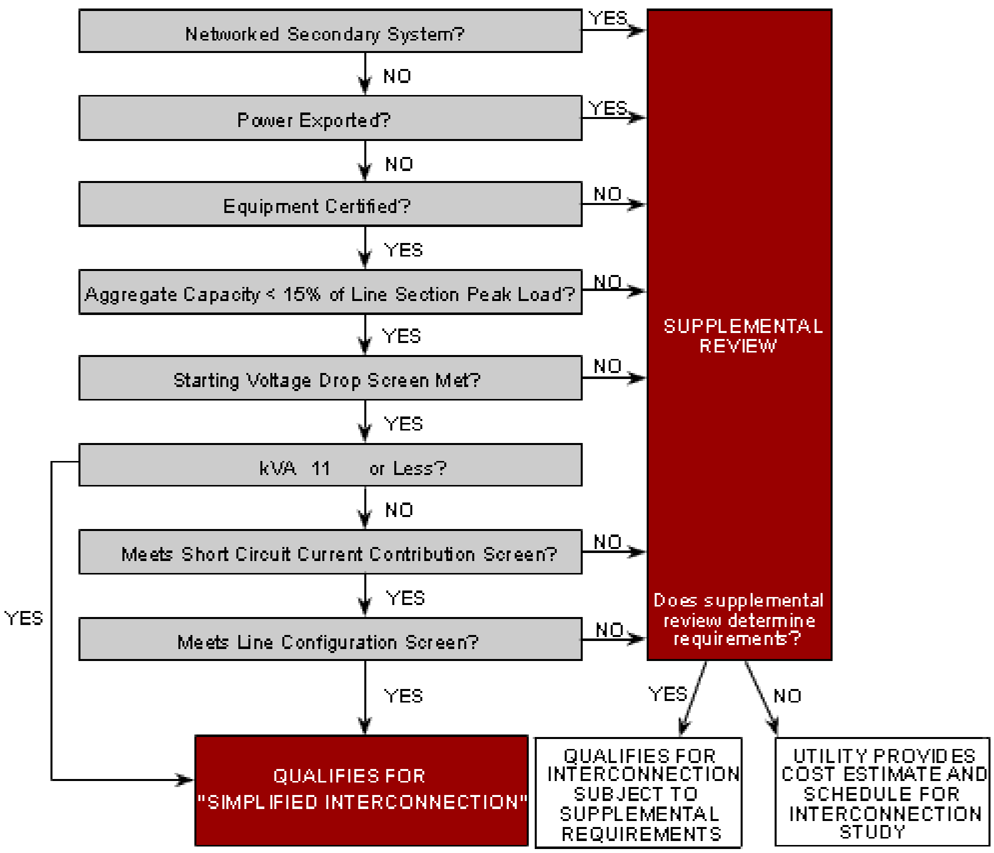


Figure 6.3.5-1: Interconnection application – initial review process

As described in the Rule 21 explanation, the interconnection application is a two-phase process involving an initial and a supplemental review. The initial review involves a series of screens that assess whether a system needs to be forwarded for a more in-depth, supplemental review. If a system passes all of the initial screens, it qualifies for a "simplified" interconnection.

Very few systems have qualified for a simplified interconnection under this process, and the process is not entirely transparent as it seems. Only SDG&E will supply the distribution system maps necessary to determine whether an electricity producer's proposed system exceeds the 15% maximum of line section peak load. Furthermore, up until recently, no manufacturer of non-solar equipment had been "certified" for simplified interconnection. This essentially forced all DG projects, aside from small solar systems, to undergo supplemental review.

Capstone Microturbines was the first company to overcome the "certification" barrier to simplified interconnection. It came at a steep cost. Despite receiving a UL listing, Capstone had to engage California's investor owned utilities (IOUs) for more than one full year in its efforts to approve both of Capstone's products (the 330 and the 660) for certification. Since then, only one other company, Plug Power, has embarked on this lengthy and time-consuming process.

As RE's systems employed un-certified equipment (Hess 220) and the size of its projects consistently exceeded 15% of the line section peak load, none of RE's projects qualified for simplified interconnection.[38]

For any projects that do not pass all of the eight screens for "simplified interconnection," a supplemental review must be performed.

Rule 21 – A Brief History

The interconnection of generation to the distribution system in California IOU territories is governed by the interconnection rule, Rule 21. Prior to 2001, Rule 21 was quite different for each of the IOUs. The rule had not been updated since the days of PURPA Qualifying Facilities (QFs). The QFs were typically very large projects costing millions of dollars; the cost of interconnecting a large QF was a very small percentage of total project cost. The old Rule 21 was burdensome and costly — not at all suited for smaller projects.

On Dec. 21, 2000, the CPUC adopted a revised Rule 21 that was approximately uniform for all utilities. This was a step forward in making interconnection utility-neutral. The IOUs are filing new advice letters now, which would make Rule 21 precisely the same for each IOU.

The costs, procedures, and technical requirements of interconnection have been clarified and standardized. Interconnection time and fee guidelines are included in the rule to make interconnection faster and less expensive. Within 10 days, the utility is to notify the applicant of receipt of the application and to note any defects in it.

Once the application is deemed complete, the utility has 10 days to complete an initial review or 20 days to complete a supplemental review.
The fee for initial review is $800; the fee for supplemental review is $600. Because the generating equipment RE installs is not yet certified for interconnection, the applications must go to supplemental review.

[38] Oddly, even after repeated requests, RE was never given an opportunity to independently verify that its proposed systems did in fact exceed the 15% maximum line contribution in either SCE or PG&E territory. RE was simply informed that its systems "failed the screen." No further data would be released as it was proprietary, and a supplemental review would be necessary.

> **Rule 21 *(cont'd)***
>
> The revised Rule 21 is a big improvement over the previous version. However, in implementation, the rule is far from perfect. Utilities have reported, for example, that they have "never received a complete application." This may be in part a reaction to the very short time frames allowed by the rule for utility review and the utilities' desire not to be at fault under the terms of the rule. The confusion over what constitutes a completed application is one that has been a barrier for RE.

The supplemental review is less delineated, allowing the utilities a wide range of latitude in how to evaluate an interconnection application. The utilities can choose to either: (a) work with the electricity producer to assess and review the project on its merits or (b) develop a scoping document for a formal interconnection study that details both the cost and the length of time to complete the interconnection study. The interconnection study does not ensure a system interconnection. Rather, it will only detail the perceived impact of the applicant's system interconnecting to the grid and the costs for local system grid upgrades that must be paid by the electricity producer to interconnect.

SDG&E and SCE never forced an RE project to undergo an interconnection study. This does not mean, however, that the process was smooth. The learning curve for both RE's project designers and the utilities was a considerable barrier against quickly completing an interconnection application.

Any interconnection documentation that needed to be revised during the supplemental review could add at least a month to the process, as Rule 21 allots the utilities 10 days for review and 20 days to respond. In the case of RE, every project application was returned to RE one to four times for revisions. This translated into an additional 2 to 5 months of utility review time prior to signing off on the final design revisions.

At the time RE began filing interconnection applications, the Rule 21 working group had not submitted the version currently under review by the CPUC, which standardizes applications across the three IOUs. The problems encountered during the supplemental review of RE's applications included:

- Application requirements were not standardized across projects.
- There was a lack of staff, in general, and, more specifically, experienced utility personnel who had an understanding of DG/CHP and the issues surrounding its safe interconnection. Together, this made the utilities overly cautious in their review.
- There was a lack of formalized communication between utility personnel and applicants.
- There was an insufficient definition and standardized protocol surrounding a "complete application."
- Different requirements across utilities stopped RE from developing a more standardized application package and required the installation of different types of protection devices.

Not including the $1,400 application fee, RE estimates that the additional costs incurred to revise various interconnection support documents were $10,000 to $20,000 per project.[39] Once an application was approved by SCE and SDG&E, the process of acquiring the interconnection agreement began.

Despite the unexpected cost increases and project start-up delays, RE found both major utilities, ultimately, reasonable and customer-driven in their desire to work with RE. Nothing could be further from RE's experience with these utilities than its experience with the Los Angeles Department of Water and Power (LADWP).

The LADWP had no formalized interconnection requirements, and when RE requested guideline documents, the LADWP claimed none existed. The LADWP interconnection policy also required that the interconnection agreement be completed prior to the technical application being filed. While negotiations over the interconnection agreement proceeded, RE began preparing its interconnection application.

Again, the LADWP had no formalized interconnection requirements or published guidelines for DG interconnection. In doing research, RE found that the LADWP had previously published interconnection standards ("handbook") for use by qualifying facilities. Upon acquiring this document, RE was instructed not to refer to it because it was out of date. Once the interconnection agreement was complete, RE submitted an interconnection application, using Rule 21 as guideline. After waiting several weeks, RE was informed that its application was insufficient. Two more times RE's applications were returned for revisions. Upon final approval, which took more than 5 months on all three projects, RE was directed to refer to the previously published "handbook" for any future projects because LADWP protection personnel use it as a "working" document and guideline.

Aside from the additional costs in time and money to revise interconnection applications in the LADWP territory, all three projects in the LADWP territory required that additional electrical equipment be installed for each generator. This was above and beyond the standard protection equipment required by the investor-owned utilities under California's Rule 21. In terms of just cost, it added more than $20,000 to the installation of *each* generator.

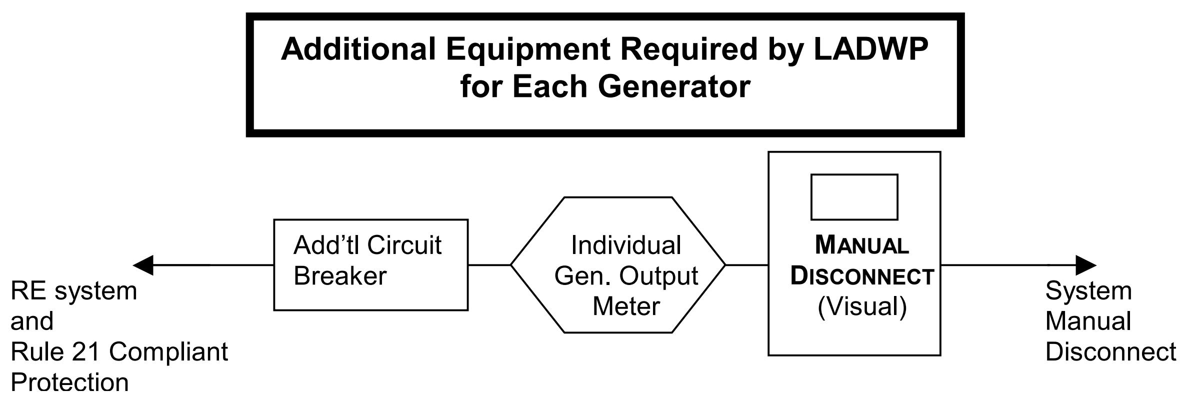


Figure 6.3.5-2: Additional equipment required by the LADWP

[39] RE's estimate, based on experience to date. This number should not be relied on because research and analysis needed to verify it have not been carried out.

6.3.6 Interconnection Agreement (Business)
Interconnection agreements define the contractual conditions that govern the relationship between the utility, its customers, and/or electricity producers seeking to interconnect with the local grid or transmission lines. Aside from QFs, few businesses attempt to interconnect any on-site generation to the grid at the PCC housed within their facilities. Historically, most utility customers in California had little choice but to receive electrical service from their local electric monopoly. Deregulation changed that and opened the door for customers to pursue electrical options such as DG.

Yet interconnection agreements have lagged behind the new regulatory framework governing the California electricity market. Despite clear precedent in California public utility case law, the utilities insisted on treating customers with electricity producers located on-site as customer interconnections. The utilities would not allow for a distinct interconnection agreement between RE (the "electricity producer") and themselves. Each utility insisted that any interconnection would only be between the utilities and the customer owning or controlling the premise on which the DG system was located. This not only put the RE business model in jeopardy, but it also forced RE to spend a large amount of time and financial resources to successfully change the rule.

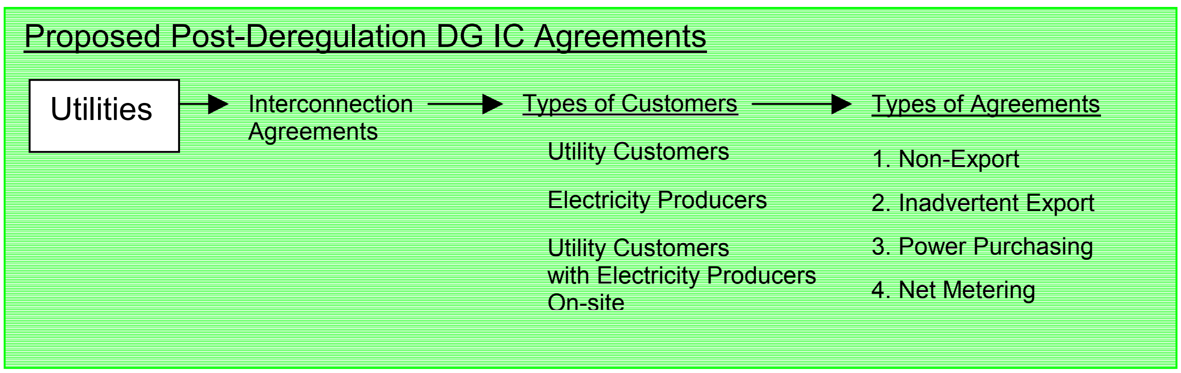


Figure 6.3.6-1: Pre- and post-restructuring agreements

Beginning in May 2001, RE began intense negotiations with SCE to change its interconnection policy. RE sought to be treated as an electricity producer. This not only involved the time of RE's senior staff but also required hiring an experienced attorney. Over the course of the summer of 2001, RE continued to negotiate with SCE and, to a lesser extent, SDG&E and the LADWP. In late August, RE supporter Congressman Brad Sherman sent a letter to the chairman of SCE requesting that it look into this inconsistent policy. In early September, RE was told that a special arrangement would be worked out not only for the pending projects but also going forward. At the following Rule 21 meeting in October, SCE announced that it would create a third type of interconnection agreement and sought to build consensus among the other utilities. Each utility pledged to work together to file a single advice letter filing. Yet the situation is still not resolved, as the advice letter was just filed by SCE this April, and PG&E and SDG&E are holding out from filing anything.

Although the opportunity cost of RE's staff to conduct these negotiations may be incalculable, the cost in attorneys' fees is estimated at more than $15,000.

Until the advice letter is approved, RE must continue to have its clients sign interconnection agreements on its behalf. This has two major ramifications. First, it creates an artificial level of accountability, where RE's clients may falsely be held liable for any problems created by RE's systems. Redundant insurance policies must be acquired, and RE's contract negotiations are lengthened. Second, RE no longer has control over the point at which its system connects to the PCC; the customer does. This puts RE in an unsavory business situation, whereby the customer can abrogate its contract with RE and effectively stop the system from operating.

In general, RE's current interconnection agreements took about 5 months to be signed and approved by all parties. RE had anticipated that this process would take only 3 to 4 weeks and that an interconnection agreement would be signed directly between the utility and RE.

6.4 Project Stage 3

6.4.1 Building Shutdown (Business)

Upon completion of a project's installation, the DG system must be integrated with the building in several ways. First and foremost, the system needs to be able to safely and economically deliver electrical power to the building. This usually takes place at the PCC. To interconnect with the building at the PCC, certain electrical situations dictate turning off the entire building's power. These building shutdowns tend to create expensive complications because they require coordinating the shutdown with not only the client but also all of the building's tenants. Excluding the solar and microturbine projects (three solar and one microturbine), nine projects required that an entire building shutdown be scheduled and executed.

In almost every case in which a building shutdown was needed, the RE project integration was delayed by an average of 20 days, forcing the projects to ultimately incur lost revenues. The shortest delay was 2 days (one building) and the longest was 56 days (one building).

Aside from further construction, nothing else can take place during this limbo period, including final utility testing of the system for interconnection sign-off, municipal approval, and source testing. In one scenario, RE was required to supply power independently to one of its client's largest tenants as it would not agree to any shutdown in building power. It cost RE an estimated additional $10,000 to supply the tenant with continuous power during the shutdown for the rest of the building. In another scenario, the RE team did not coordinate well with the local utility — which must also be present during the shutdown — and the shutdown had to be postponed and rescheduled a month later. Aside from the financial implications, RE caused the client serious consternation and put the entire project under a bad light with the building's 87 inconvenienced tenants (more than 3,000 people).

6.4.2 Building and Safety Sign-Off (Regulatory – Municipal)

Once a system is properly integrated into the building and the equipment has been tested, RE invites the local municipality (or county, in the case of unincorporated Marina del Rey) to inspect the project. The building and safety officials inspect the project to make sure that it meets local and national safety codes for both electrical and mechanical equipment.

Despite earlier problems obtaining building permits, the final inspection by municipal officials generally went smoothly and caused no further delays, except for projects in the city of Los Angeles. In general, the building and safety officials in the city of Los Angeles took a very cautious approach toward the permitting of RE's three systems in the city. One of their main concerns was the safe grounding of the system in case of protection failure and immediate shutdown. Although they did not end up requiring any additional equipment, they insisted on making two separate visits a week apart, further delaying system commissioning by another week.

6.4.3 Final Interconnection Inspection (Regulatory – Regional)

Given all of the upfront work done together with RE and the various utilities, final system inspection was never an issue. Generally, inspections were scheduled a week in advance. Oddly though, the SDG&E final interconnection inspections were the only ones that included the same protection staff from the interconnection application approval process. Field engineers conducting the final interconnection inspection in the other territories invariably would comment on the excessive amount of protection required by the engineers "back at the office."

6.4.4 Permit to Operate (Regulatory Regional)

The permit to operate (PTO) is issued by the local air quality district after source testing is completed. Given the technical complexity involved in compiling a report, RE or — depending on the project — Hess contracts with an independent third party to conduct the source test that is eventually submitted for review by the district.

Within the ATC, the protocols are given for conducting the submitted source test report. Generally, the source test must take place within 60 days of the first start-up, the engines are tested separately, and certain types of measuring equipment need to be employed (e.g., xj200 particle traps). For both districts, a final PTO is good for 2 years with only compliance paperwork filed the first year into operation.

In both districts, until the final PTO is issued, the ATC along with a submitted source test act as an interim PTO. In essence, the districts screen the source test report for obvious problems or variances and, if none can be found, they do not rush a deeper perusal or the generation of final paperwork for the PTO, as it does not necessarily impact equipment operation.

RE's first series of completed projects passed the districts' source testing requirements with no problems. This, however, created an unintended consequence: the length of time for RE to receive a PTO was rather long. For example, the source testing for Oceanside was completed in December 2001, and the reports were submitted to the AQMD that same month. RE did not receive the permit to operate for Oceangate until sometime in April, despite having passed every test.

Two other sites that have completed their source testing and received their PTOs are 5200 W. Century and World Savings. The W. Century project completed its source testing on Oct. 12, 2001, and received the PTO on Feb. 19, 2002 — a total of approximately 4 months. The World Savings project, on the other hand, completed its source testing on Oct. 4, 2001, and received its

PTO on Nov. 12, 2001 — a total of approximately 5 weeks. Projects in San Diego that had their source tests submitted in February 2002 have yet to receive their PTOs.

6.4.5 RealEnergy Project Funding

Of the 13 systems, only four that were eligible for incentives actually received funding. The funding ranged from $254,000 to $574,000. Many sites were not eligible because they were located in municipal territory. The sites that were ineligible for funding were ineligible because no CEC funding was available or because installation occurred before the CPUC incentive program started. Skypark and Genesee were ineligible for funding because these sites were not cogeneration plants. The three sites in LADWP's territory were ineligible for funding because the sites were located in municipal utility territory.

6.5 Conclusion

Current Markets for DG Technology in California

The market for DER in California must be founded on sound economics. Those technologies with the most positive economic return will emerge as technologies of preference. For DER to play a sustained role in power supply, it must be competitive with utility-provided power pricing and as convenient to obtain as utility-provided power. DER will be funded by private enterprise where utility power cost is highest. Basic economics dictate the highest costs occur where supply is limited; therefore, DER will play a smaller role in various irrigation districts, some municipalities, or WAPA because of low-cost power in these areas.

One factor that contributes to the cost of implementing DER is that many technologies are in their first round of product production and per-unit cost is high. As manufacturers increase production, the cost for many of these technologies will decrease significantly.

For select applications, DER make economic sense today. RE has shown that CHP in commercial operations with high capacity factor is economically viable during on- and mid-peak tariff periods when gas prices are not too high.

Educating local regulators and permitting authorities is still an issue and a cost for many projects, as this report demonstrates. Many utility personnel also lack training. Some older field personnel may have a bias against DG from the days of PURPA. Utilities themselves are not aligned with allowing DG to be installed because it decreases utility distribution system revenue, which is based on kilowatts flowing through the lines. To this extent, investor-owned and many municipal utilities in California are not agnostic about DG and have been cooperative only in select instances. A mechanism decoupling rates from kilowatt-hour distribution — such as the Electric Rate Adjustment Mechanism of the days of demand-side management projects — might help, though it is likely to be opposed by the IOUs because it is a ratepayer subsidy for DG. The question remains how long utilities can resist DG as the technologies come within economic reach of an ever-increasing portion of the rate base.

Appendix: Meter Outputs

1. Meter on the Utility Bus – The DEIS Output

The Generator Meter for the DEIS is the PML ION 7500. For each output under each category, the description of the characteristic measured will be follow by its variable name:

Description = "Output name"

Voltage

Voltage line-to-line average mean = "VLL avg mean"
Voltage line-to-line phase a and phase b mean = "VLL ab mean"
Voltage line-to-line phase b and phase c mean = "VLL bc mean"
Voltage line-to-line phase c and phase a mean = "VLL ca mean"
Voltage unbalanced mean = "V unbalanced mean"
Voltage line-to-line average high = "VLL avg high"
Voltage line-to-line phase a and b high = "VLL ab high"
Voltage line-to-line phase b and c high = "VLL bc high"
Voltage line-to-line phase a and c high = "VLL ca high"
Voltage unbalanced high = "V unbalanced high"
Voltage line-to-line average low = "VLL avg low"
Voltage line-to-line phase a and b low = "VLL ab low"
Voltage line-to-line phase b and c low = "VLL bc low"
Voltage line-to-line phase c and a low = "VLL ca low"
Voltage unbalanced low = "V unbalanced low"

Current

Current average mean = "I avg mean"
Current phase a mean = "I a mean"
Current phase b mean = "I b mean"
Current phase c mean = "I c mean"
Current average high = "I avg high"
Current phase a high = "I a high"
Current phase b high = "I b high"
Current phase c high = "I c high"
Current average low = "I avg low"
Current phase a low = "I a low"
Current phase b low = "I b low"
Current phase c low = "I c low"

Power

Kilowatt total mean = "kW total mean"
Kilovolt Ampere Reactive total mean = "kVAR total mean"
Kilovolt Ampere total mean = "kVA total mean"
Kilowatt total high = "kW total high"
Kilovolt Ampere Reactive total high = "kVAR total high"

Kilovolt Ampere total high = "kVA total high"
Kilowatt total low = "kW total low"
Kilovolt Ampere Reactive total low = "kVAR total low"
Kilovolt Ampere total low = "kVA total low"

Frequency/Power Factor
Power factor lag mean = "PF lag mean"
Power factor lead mean = "PF lead mean"
Frequency mean = "Freq mean"
Power factor lag high = "PF lag high"
Power factor lead high = "PF lead high"
Frequency high = "Freq high"
Power factor lag low = "PF lag low"
Power factor lead low = "PF lead low"
Frequency low = "Freq low"

Energy/Demand
Kilowatt hour delivered interval = "kWh del Int"
Kilowatt received interval = "kW rec Int"
Kilovolt Ampere Reactive hour delivered interval = "kVARh del Int"
Kilovolt Ampere Reactive hour received interval = "kVARh rec Int"

Harmonics
Voltage 1 total harmonic distortion mean = "V1 THD (threshold) mean"
Voltage 2 total harmonic distortion mean = "V2 THD mean"
Voltage 3 total harmonic distortion mean = "V3 THD mean"
Current 1 total harmonic distortion mean = "I 1 THD mean"
Current 2 total harmonic distortion mean = "I2 THD mean"
Current 3 total harmonic distortion mean = "I3 THD mean"
Current 1 K factor mean = "I1 K Fac mean"
Current 2 K factor mean = "I2 K Fac mean"
Current 3 K factor mean = "I3 K Fac mean"
Voltage 1 total harmonic distortion high = "V1 THD high"
Voltage 2 total harmonic distortion high = "V2 THD high"
Voltage 3 total harmonic distortion high = "V3 THD high"
Current 1 total harmonic distortion high = "I1 THD high"
Current 2 total harmonic distortion high = "I2 THD high"
Current 3 total harmonic distortion high = "I3 THD high"
Current 1 K factor mean high = "I1 K Fac high"
Current 2 K factor mean high = "I2 K Fac high"
Current 3 K factor mean high = "I3 K Fac high"

Sag/Swell
Duration of Sag/Swell = "Duration"
Magnitude of Phase 1 of Sag/Swell = "Magnitude Phase 1"
Magnitude of Phase 2 of Sag/Swell = "Magnitude Phase 2"

Magnitude of Phase 3 of Sag/Swell = "Magnitude Phase 3"
Cause = "Cause"
Timestamp = "Timestamp"

Waveforms
Timestamp = "Timestamp"
Label describing the cause of a waveform event = "cause_ion"
Value describing the cause of a waveform event = "cause_value"
Label describing the effect of a waveform event = "effect_ion"
Value describing the effect of a waveform event = "effect_value"
Voltage 1 waveform = "V1"
Voltage 2 waveform = "V2"
Voltage 3 waveform = "V3"
Current 1 waveform = "I1"
Current 2 waveform = "I2"
Current 3 waveform = "I3"

2. Generator Meter for Photovoltaics – The DEIS Output

The outputs from the PV Generator Meter, a Power Measurement model 7350,[40] are as follows:

Voltage
Voltage line-to-line average mean = "VLL avg mean"

Current
Current average mean = "I avg mean"

Power
Kilowatt total mean = "kW total mean"
Kilovolt Ampere Reactive total mean = "kVAR total mean"
Kilovolt Ampere total mean = "kVA total mean"

Freqency/Power Factor
Power factor sign mean = "PF sign mean"
Frequency mean = "Freq mean"

Energy/Demand
Kilowatt sliding window demand = "kW swd"
Kilovolt Ampere Reactive sliding window demand = "kVAR swd"
Kilovolt Ampere sliding window demand = "kVAR swd"
Kilowatt hour imported = "kWh imp"
Kilowatt hour exported = "kWh exp"
Kilowatt hour net = "kWh net"
Kilovolt Ampere Reactive hour imported = "kVARh imp"
Kilovolt Ampere Reactive hour exported = "kVARh exp"

[40] The Power Measurement model 7350 was the first model used by RE. It is replaced in later projects by the model 7500, which is a more robust and capable system.

Kilovolt Ampere Reactive hour net = "kVARh net"
Kilovolt Ampere hour total = "kVAh total"

Harmonics

Voltage 1 total harmonic distortion mean = "V1 THD mean"
Voltage 2 total harmonic distortion mean = "V2 THD mean"
Voltage 3 total harmonic distortion mean = "V3 THD mean"
Current 1 total harmonic distortion mean = "I 1 THD mean"
Current 2 total harmonic distortion mean = "I2 THD mean"
Current 3 total harmonic distortion mean = "I3 THD mean"

Sag/Swell

Magnitude of Phase 1 of Sag/Swell = "Magnitude Phase 1"
Magnitude of Phase 2 of Sag/Swell = "Magnitude Phase 2"
Magnitude of Phase 3 of Sag/Swell = "Magnitude Phase 3"
Cause = "Cause"
Timestamp = "Timestamp"

Waveforms

Label describing the cause of a waveform event = "cause_ion"
Value describing the cause of a waveform event = "cause_value"
Label describing the effect of a waveform event = "effect_ion"
Value describing the effect of a waveform event = "effect_value"
Voltage 1 waveform = "V1"
Voltage 2 waveform = "V2"
Voltage 3 waveform = "V3"
Current 1 waveform = "I1"
Current 2 waveform = "I2"
Current 3 waveform = "I3"

3. Generator Meter for IC Engines – The DEIS Output

The Generator Meter for ICE in the DEIS is the PML ION 7500. Outputs are as follows.

Voltage

Voltage line-to-line average mean = "VLL avg mean"
Voltage line-to-line phase a and phase b mean = "VLL ab mean"
Voltage line-to-line phase b and phase c mean = "VLL bc mean"
Voltage line-to-line phase c and phase a mean = "VLL ca mean"
Voltage unbalanced mean = "V unbalanced mean"
Voltage line-to-line average high = "VLL avg high"
Voltage line-to-line phase a and b high = "VLL ab high"
Voltage line-to-line phase b and c high = "VLL bc high"
Voltage line-to-line phase a and c high = "VLL ca high"
Voltage unbalanced high = "V unbalanced high"
Voltage line-to-line average low = "VLL avg low"
Voltage line-to-line phase a and b low = "VLL ab low"

Voltage line-to-line phase b and c low = "VLL bc low"
Voltage line-to-line phase c and a low = "VLL ca low"
Voltage unbalanced low = "V unbalanced low"

Current
Current average mean = "I avg mean"
Current phase a mean = "I a mean"
Current phase b mean = "I b mean"
Current phase c mean = "I c mean"
Current average high = "I avg high"
Current phase a high = "I a high"
Current phase b high = "I b high"
Current phase c high = "I c high"
Current average low = "I avg low"
Current phase a low = "I a low"
Current phase b low = "I b low"
Current phase c low = "I c low"

Power
Kilowatt total mean = "kW total mean"
Kilovolt Ampere Reactive total mean = "kVAR total mean"
Kilovolt Ampere total mean = "kVA total mean"
Kilowatt total high = "kW total high"
Kilovolt Ampere Reactive total high = "kVAR total high"
Kilovolt Ampere total high = "kVA total high"
Kilowatt total low = "kW total low"
Kilovolt Ampere Reactive total low = "kVAR total low"
Kilovolt Ampere total low = "kVA total low"

Freqency/Power Factor
Power factor lag mean = "PF lag mean"
Power factor lead mean = "PF lead mean"
Frequency mean = "Freq mean"
Power factor lag high = "PF lag high"
Power factor lead high = "PF lead high"
Frequency high = "Freq high"
Power factor lag low = "PF lag low"
Power factor lead low = "PF lead low"
Frequency low = "Freq low"

Energy/Demand
Kilowatt hour delivered interval = "kWh del Int"
Kilowatt received interval = "kW rec Int"
Kilovolt Ampere Reactive hour delivered interval = "kVARh del Int"
Kilovolt Ampere Reactive hour received interval = "kVARh rec Int"

Harmonics

Voltage 1 total harmonic distortion mean = "V1 THD (threshold) mean"
Voltage 2 total harmonic distortion mean = "V2 THD mean"
Voltage 3 total harmonic distortion mean = "V3 THD mean"
Current 1 total harmonic distortion mean = "I 1 THD mean"
Current 2 total harmonic distortion mean = "I2 THD mean"
Current 3 total harmonic distortion mean = "I3 THD mean"
Current 1 K factor mean = "I1 K Fac mean"
Current 2 K factor mean = "I2 K Fac mean"
Current 3 K factor mean = "I3 K Fac mean"
Voltage 1 total harmonic distortion high = "V1 THD high"
Voltage 2 total harmonic distortion high = "V2 THD high"
Voltage 3 total harmonic distortion high = "V3 THD high"
Current 1 total harmonic distortion high = "I1 THD high"
Current 2 total harmonic distortion high = "I2 THD high"
Current 3 total harmonic distortion high = "I3 THD high"
Current 1 K factor mean high = "I1 K Fac high"
Current 2 K factor mean high = "I2 K Fac high"
Current 3 K factor mean high = "I3 K Fac high"

Sag/Swell

Duration of Sag/Swell = "Duration"
Magnitude of Phase 1 of Sag/Swell = "Magnitude Phase 1"
Magnitude of Phase 2 of Sag/Swell = "Magnitude Phase 2"
Magnitude of Phase 3 of Sag/Swell = "Magnitude Phase 3"
Cause = "Cause"
Timestamp = "Timestamp"

Waveforms

Timestamp = "Timestamp"
Label describing the cause of a waveform event = "cause_ion"
Value describing the cause of a waveform event = "cause_value"
Label describing the effect of a waveform event = "effect_ion"
Value describing the effect of a waveform event = "effect_value"
Voltage 1 waveform = "V1"
Voltage 2 waveform = "V2"
Voltage 3 waveform = "V3"
Current 1 waveform = "I1"
Current 2 waveform = "I2"
Current 3 waveform = "I3"

4. Absorption Chiller/Thermal Capture System – The DEIS Input

Generator Meter

Digital Input (DI): OK to run generators (from Bldg EMS)

DI: Host wants chilled water (from Bldg EMS)
Digital Output (DO): Request cooling tower fan control
Analog Output (AO): kW production
DO: Chiller ready to start
AO: Absorption chiller, supply temperature to cooling tower
AO: Absorption chiller supply water temperature to building

Field Hardware I/O modules
Analog Input (AI): Chilled water flow
AI: Chilled water supply temperature
AI: Chilled water return temperature
[PML meter uses the previous three inputs to calculate tons & ton-hours of cooling provided to the building host.]
AI: Jacket water supply temp from engines
AI: Jacket water entering absorption chiller temperature
AI: Jacket water leaving absorption chiller temperature
AI: Jacket water entering dump heat exchanger temperature
AI: Jacket water return temperature to engines
AI: Jacket water supply temp from building cooling towers
AI: CDWS Condenser water supply to absorption chiller
Condenser water return temp: above x, turn on cooling tower fan; below y, turn off cooling tower fan.
AI: CDWR Condenser water return from absorption chiller to tower
AI: Hx CDWS temp after Mix valve
AI: Hx CDWR temp to tower

AI: Hx1 Leaving tower water temp
AI: Hx2 Leaving tower water temp
AI: Absorption chiller condenser water pump Amps
AI: Absorption chiller chilled water pump Amps
AI: Absorption chiller jacket water control valve position
AI: Hx1 pump Amps
AI: Hx2 pump Amps
AI: Jacket water pump amps
AI: Tower bypass valve position

Engine 1-n
DO: Hx—1-n pump S/S
DO: Jacket water—1-n pump S/S

Absorption Chiller 1-n
DO: CDW Condenser water pump S/S
DO: CHW Chilled water pump S/S
AO: Jacket water control valve position command
AO: Tower bypass valve command

REPORT DOCUMENTATION PAGE

Form Approved
OMB NO. 0704-0188

1. AGENCY USE ONLY (Leave blank)

2. REPORT DATE
April 2003

3. REPORT TYPE AND DATES COVERED
Subcontract; Phase 1 Report

4. TITLE AND SUBTITLE
Development, Demonstration, and Field Testing of Enterprise-Wide Distributed Generation Energy Management System: Phase 1 Report

5. FUNDING NUMBERS
DP03.1001
NAD-1-30605-11

6. AUTHOR(S)

7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES)
RealEnergy
5957 Variel Avenue
Woodland Hills, CA 91367
Tel: 818.610.2300

8. PERFORMING ORGANIZATION REPORT NUMBER

9. SPONSORING/MONITORING AGENCY NAME(S) AND ADDRESS(ES)
National Renewable Energy Laboratory
1617 Cole Blvd.
Golden, CO 80401-3393

10. SPONSORING/MONITORING AGENCY REPORT NUMBER
NREL/SR-560-33581

11. SUPPLEMENTARY NOTES
NREL Technical Monitor: Holly Thomas

12a. DISTRIBUTION/AVAILABILITY STATEMENT
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

12b. DISTRIBUTION CODE

13. ABSTRACT *(Maximum 200 words)*

This report describes RealEnergy's evolving distributed generation command and control system, called the "Distributed Energy Information System" (DEIS). This system uses algorithms to determine how to operate distributed generation systems efficiently and profitably. The report describes the system and RealEnergy's experiences in installing and applying the system to manage distributed generators for commercial building applications.

The report is divided into six tasks. The first five describe the DEIS; the sixth describes RE's regulatory and contractual obligations.

- Task 1: Define Information and Communications Requirements
- Task 2: Develop Command and Control Algorithms for Optimal Dispatch
- Task 3: Develop Codes and Modules for Optimal Dispatch Algorithms
- Task 4: Test Codes Using Simulated Data
- Task 5: Install and Test Energy Management Software
- Task 6: Contractual and Regulatory Issues

14. SUBJECT TERMS
RealEnergy; command and control; distributed energy information system; DEIS; communication and control; energy management; National Renewable Energy Laboratory; NREL; CHP

15. NUMBER OF PAGES

16. PRICE CODE

17. SECURITY CLASSIFICATION OF REPORT
Unclassified

18. SECURITY CLASSIFICATION OF THIS PAGE
Unclassified

19. SECURITY CLASSIFICATION OF ABSTRACT
Unclassified

20. LIMITATION OF ABSTRACT
UL

NSN 7540-01-280-5500

Standard Form 298 (Rev. 2-89)
Prescribed by ANSI Std. Z39-18
298-102