Appendix II
Final Domain Analysis Report

CEC-PIER Project 500-98-040
Intelligent Software Agents for Control and Scheduling of Distributed Generation

Domain Analysis
Final Report

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LEGAL NOTICE

Executive Summary

Alternative Energy Systems Consulting, Inc. (AESC) is currently under contract to the California Energy Commission (CEC) for development and demonstration of a scheduler / controller of Distributed Energy Resources (DER) that will operate in the California competitive energy marketplace. Specifically, the CEC-PIER project titled, “Intelligent Software Agents for Control & Scheduling of Distributed Generation”, provides funding to demonstrate the viability of scheduling and/or dispatching one or more distributed energy resources using intelligent software agents. Where an intelligent agent is a software-based device that acts on behalf of the user and has the ability to exploit knowledge, tolerate errors, reason with symbols, learn and reason in real time, and communicate with other agents or entities. Multiple agents acting independently, in a cooperative fashion, are called an agency. For this project we will develop and test a prototype agency called the Distributed Energy Resource Scheduler (DER*S).

The preliminary domain analysis was the first task in the CEC-PIER project. In this task AESC analyzed the California energy industry in order to characterize the potential DER*S markets (e.g., end-users/potential owners, benefits and capabilities). The results of this analysis effort were summarized in the Preliminary Domain Analysis Report. During the preliminary domain analysis effort AESC identified basic DER*S operating scenarios based on analysis of the current energy marketplace in California, potential DER technologies and their potential benefits. In a related effort, AESC formed a market participant evaluation group comprised of key individuals and companies that operate in, or have knowledge of, the competitive energy industry and/or distributed energy resources. The market participant evaluation group provided vital feedback on key issues and questions raised in the preliminary domain analysis. Specifically, the market participant group was used to prioritize the potential DER*S markets. Results of this market research effort are summarized in the Market Research Report. Ultimately, our objective was to characterize the DER*S operating environment, or domain, for the most likely DER*S markets.

We concluded from our analysis that DER*S is only applicable to DER equipment that can be dispatched. Non-dispatchable technologies, such as wind, solar, and energy efficiency, are not compatible with DER*S because their production output is not controllable. However, in some DER technologies, the addition of energy storage *can* provide dispatching capability. Other DER technologies such as ultracapacitors and SMES provide short bursts (i.e., milliseconds) of electric energy to improve power quality. Although dispatchable, these technologies are triggered by power quality events and do not affect the aggregate value of electric energy. Curtailable loads are dispatchable but to varying degrees depending on the type of load involved. For example, remote control of cycling of residential or small commercial air conditioners is a dispatchable resource that could be bid into the ancillary services market as non-spinning reserve (available within 10 minutes). Loads (i.e., process loads, etc.) requiring additional time could still be classified and scheduled/dispatched as replacement reserves (available within 60 minutes).

Entities that could benefit from DER*S operation are envisioned as building owners/operators, ESCOs (or other load aggregator) or Utility Distribution Companies (UDC). A building owner / operator could benefit by using DER scheduling to lower overall energy costs and increase power supply reliability. An ESCO (or other load aggregator) could use DER*S for bundling of customer on-site DER services with power and fuel contracts to increase customer value and improve contract margins. DER*S could also enable building owners/operators and ESCOs to bid into one or more of the California energy or ancillary services markets. UDC participation in DER*S applications may be based on a connection between potential DER benefits and UDC Performance Based Ratemaking (PBR) mechanisms. Several studies have identified power delivery cost and performance benefits derived from DER installations and past studies by the Electric Power Research Institute (EPRI), Pacific Gas and Electric (PG&E) and others have identified potential UDC benefits from DER that include; capital deferral, reduced energy loss and improved reliability. Direct ownership of DER assets by Utility Distribution Companies (UDC) continues to be the subject of debate. Therefore in the near-term it is unlikely that UDCs will own or operate DER assets, however this could change as the marketplace continues to evolve.

The DER*S operating environment can vary significantly in terms of the number and types of entities that are involved. Based on our assessment of the California marketplace we believe that there are three basic DER*S operating scenarios, each with a differing level of complexity. In the first scenario, DER*S operates one or more DER assets at a single site to minimize site energy costs. DER*S will monitor site load and DER performance and access weather data via the Internet in order to predict site loads. In addition, or in lieu of this information, DER*S may receive pricing signal(s) from the local UDC depending on the applicable electric rate. Electricity and possibly for natural gas prices (depending on the DER asset involved) could also be accessed via the Internet as needed. In this scenario, DER*S operates the DER asset to reduce on-site loads and associated costs without any direct involvement in the various energy and demand markets (CalPX or CAISO). Note that this operating scenario could also apply to DER*S scheduling/dispatching of DER assets installed at a substation with UDC operation / ownership of DER*S (if UDC ownership/operation of DER assets is permitted).

The second scenario provides for DER*S aggregation of multiple assets without direct involvement in any of the competitive markets. Under this operating scenario DER*S aggregates load or otherwise coordinates operation of DER assets at multiple sites. This would allow sites/businesses to respond to interruptible rates or could provide an ESCO with load shaping capabilities. The DER*S at each individual site would have knowledge of site load and DER asset performance and would “represent” its site’s interests in responding to UDC pricing signals (if provided) or ESCO load shaping constraints. As with the single site operating scenario, DER*S could access the Internet for weather and possibly for electricity and natural gas prices depending on the DER asset involved. In this scenario, DER*S operates to reduce site energy costs but with the added complexity of operating in conjunction with other DER*S equipped sites. In this scenario there is no direct involvement with external competitive markets.

The third operating scenario involves both aggregation of multiple assets and participation in one or more of the competitive markets. This operating scenario is similar to the second scenario in that multiple sites are involved. However, in this case DER*S is responding to, and participating in, one or more of the competitive markets operated by either the CalPX or CAISO. Market participation could be either via the CalPX or another Scheduling Coordinator (SC). In this scenario, the DER*S agents would have to balance site loads and costs against the potential return of bidding into one or more of the competitive markets. For instance, if high ancillary service pricing is predicted then bidding of standby generator capacity or curtailable load(s) could be justified.

The market participant group identified the first two operating scenarios as the most likely to occur in the near-term and intermediate-terms. Although in both cases, UDC involvement in the form of ownership or operation of DER/DER*S assets is uncertain. While DER*S could enable direct involvement in California energy and demand markets (operating scenario 3) this is seen as unlikely in the near-term. This type of involvement is seen as a more long term operating scenario as the California market continues to evolve and DER integration into the California marketplace progresses.

Based on the three basic operating scenarios and the potential DER assets involved we have identified the most likely DER*S capabilities, which can be divided into two basic categories. The first category contains essential capabilities and the second contains capabilities that could improve product performance or market acceptance (e.g., “bells and whistles”). The seven basic capabilities considered essential to DER*S product viability are:

- Monitor and Forecast DER Asset Performance / Output
- Monitor and Forecast Site Load (energy and demand) Requirements
- Monitor and Forecast Relevant Market Pricing
- Schedule DER Operation to Maximize Economic Benefit
- Graphical User Interface (GUI)
- Data Storage & Retrieval
- Communicate with External Entities (i.e., Internet, DER controls, etc.)

Additional capabilities that would improve DER*S product performance or market acceptance are primarily related to automation of various aspects of DER*S-DER operations. . These additional capabilities are:

- Automatic Retrieval of Routine Data
- Direct Connection and Dispatch of DER Asset(s)
- Diagnose Building and/or DER Performance Problems
- Direct Communication and Data Transfer with Affected Agencies (if applicable)
- Automatic Verification / Resolution of Settlement Statements (if applicable)

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1.0 Introduction

This domain analysis effort is the first task in a California Energy Commission PIER research and development project titled, "Intelligent Software Agents for Control & Scheduling of Distributed Generation". The overall project objective is to demonstrate the viability of using intelligent software agents for scheduling and dispatching of one or more distributed energy resources (e.g., distributed generation, energy storage, cogeneration, etc.) in a competitive market. An intelligent agent is a software-based device that acts on behalf of the user and has the ability to exploit knowledge, tolerate errors, reason with symbols, learn and reason in real time, and communicate in an appropriate language. Multiple agents operating in conjunction, as an agency, can achieve goals/objectives that would not be otherwise achievable by a single agent. For this project we will develop and test a prototype agency called the Distributed Energy Resource Scheduler (DER*S) that will schedule operation of distributed energy resource (DER) equipment in a competitive energy market.

The purpose of the domain analysis effort was to analyze the California energy industry in order to characterize the potential markets (e.g., end-users/potential owners, benefits and capabilities) for DER*S. In a related effort, we established a market participant evaluation group comprised of key individuals and companies that operate in, or have knowledge of, the competitive energy industry and/or distributed energy resources. This market participant evaluation group provided vital feedback on key issues and questions. The overall domain analysis effort was an iterative effort where information gained from the market evaluation group raised additional questions requiring additional analysis of the domain. Ultimately, it was our objective to characterize the DER*S operating environment, or domain, for the most likely DER*S markets.

Key questions that were examined in the domain analysis include:

- What types and quantities of distributed energy resource equipment are and will be deployed?
- How does a distributed energy resource provide benefit to the end-user in a competitive environment?
- Does use of intelligent software agents provide additional opportunities for distributed energy resource savings? (i.e., aggregation, etc.)
- What other entities must a distributed energy resource communicate and/or interconnect with in order to operate effectively?
- Are there market factors that impact the commercial viability of advanced control (i.e., infrastructure considerations, rates/pricing of energy and ancillary services, utility distribution company ownership of distributed energy resources, etc.)?
- What is the current state-of-the-art in distributed energy resource control equipment?

- What are the technological barriers to successfully implementing distributed energy resource scheduler using intelligent agent technology?

Ultimately, the information gained in this effort will be used to set broad goals and objectives for the DER*S prototype product.

To fully cover the domain of interest we will first summarize potential DER*S operating scenarios and associated capabilities showing how DER*S could be integrated into the competitive marketplace. This will be followed by a discussion of the California competitive market as it currently exists as well as the basics of DER technology. A discussion of how DER, and potentially DER*S, achieves benefits for a variety of market participants is also provided.

2.0 DER*S Description

For purposes of this domain analysis we will think of DER*S as a “black box” with capabilities to be defined by the target marketplace. Our discussion will therefore focus on potential operating scenarios and the associated DER*S capabilities necessary for each.

2.1 *DER*S Operating Scenarios*

The DER*S operating environment can vary significantly in terms of the number and types of entities that are involved. Our analysis (see DER technology discussion) leads us to believe that there are three basic operating scenarios for DER*S in a competitive marketplace, each with a differing level of complexity. Our discussion of DER*S operation will therefore be divided into three basic operating scenarios. In the first scenario, DER*S operates at a single site to minimize site energy costs. The second scenario provides for DER*S aggregation of multiple assets without direct involvement in any of the competitive markets. The third scenario involves both aggregation of multiple assets and participation in one or more of the competitive markets.

Single Site Operation

In this first and simplest operating scenario, DER*S operates one or more DER assets at a single site to minimize energy costs. In this configuration (see Figure 1), DER*S will monitor site load and DER performance. DER*S will access weather data via the Internet in order to predict site loads. Depending on the DER asset involved DER*S may also access the Internet for electricity and possibly for natural gas prices. DER*S may receive pricing signal(s) from the local UDC depending on the applicable electric rate, which would in turn affect the decision process and the associated data requirements.

In this scenario, DER*S operates the DER asset to reduce on-site loads and associated costs without any direct involvement in the various energy and demand markets. No direct contact is therefore required with either the CalPX or CAISO. Note that this configuration could also apply to DER installation at a substation with UDC operation / ownership (if UDC ownership or operation of DER assets were allowed).

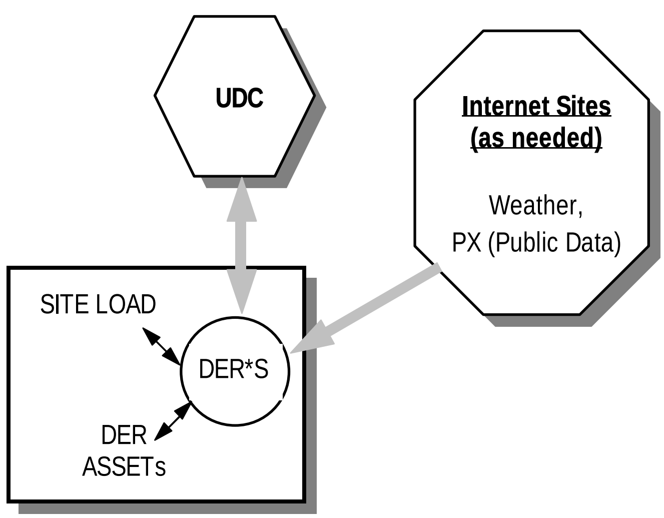

Figure 1 – Single Site DER*S Operation

Given the simplicity of this operating scenario one could argue that there is little use for an agent-based scheduler employing distributed processing. The possible exception would be sites with multiple DER assets since individual DER assets could conceivably be represented by individual by agents.

Multiple Asset Operation – No Market Participation

Under this operating scenario (see Figure 2) DER*S aggregates load or otherwise coordinates operation of DER assets at multiple sites. This would allow sites/businesses to respond to interruptible rates while still maintaining critical processes. The DER*S at each individual site would have knowledge of site load (size, priority of served loads, etc.) and DER asset performance. Each DER*S would "represent" its site's interests in responding to UDC pricing signals as a group. As with the single site operating scenario, DER*S could access the Internet for weather and possibly for electricity and natural gas prices depending on the DER asset involved.

In this scenario, DER*S operates to reduce site energy costs but with the added complexity of operating in conjunction with other DER*S equipped sites. In the case of the interruptible rate scenario, each DER*S could "bid" its load reduction amount into a pseudo-market and would act according to the outcome. Note that the figure shows a single connection to the UDC with this information passed to the remaining DER*S. In another operating scenario, DER*S equipped sites could operate cooperatively to provide aggregated load shaping for an ESCO. In that event, the ESCO could send out a pseudo-pricing signal similar to a UDC or even broadcast a load reduction goal to the DER*S agency for implementation. The DER*S agency would then cooperatively determine the best course of action that both meets the ESCO and individual site needs.

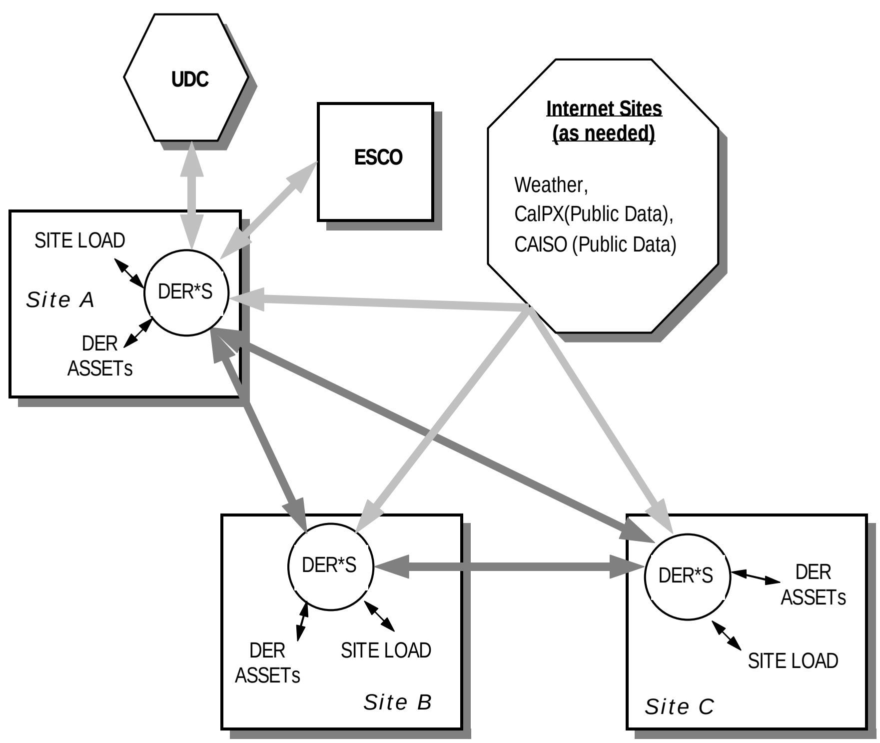

Figure 2 – DER*S Multiple Sites – No Market Participation

As with the previous scenario there is no direct involvement in the competitive markets since DER*S is responding to UDC rates and/or other pricing signals. No direct contact is therefore required with either the CalPX or CAISO. Note that this configuration could also apply to DER installations at multiple substations with UDC operation in response to distribution system loads (if UDC ownership or operation of DER assets were allowed).

Multiple Asset Operation – Direct Market Participation

The third operating scenario (see Figure 3) is similar to the second scenario in that multiple sites are involved. However, in this case DER*S is responding to, and participating in, one or more of the competitive markets operated by either the CalPX or CAISO. The figure arbitrarily shows three DER*S equipped sites, each with a DER*S

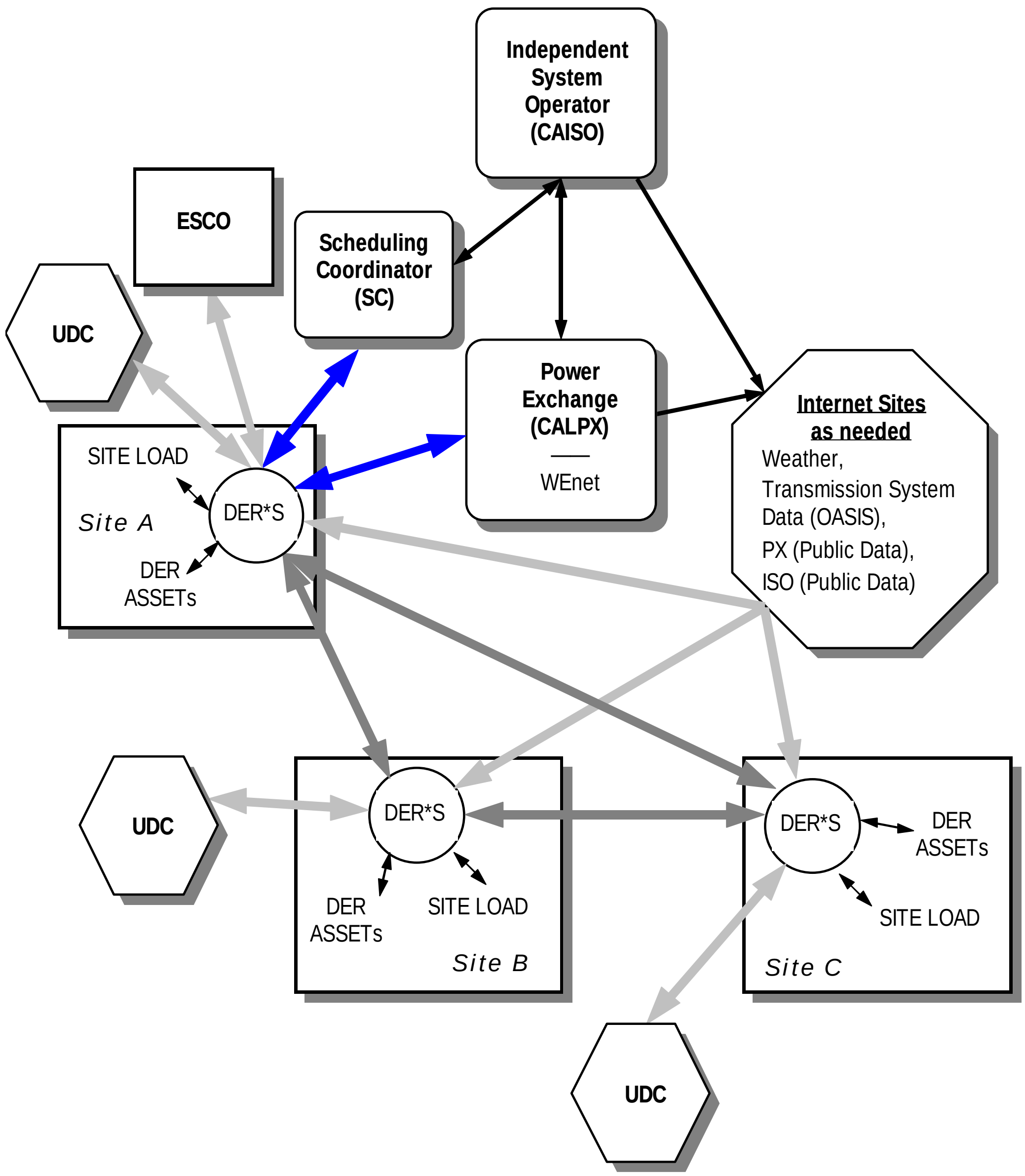

Figure 3 – DER*S Multiple Sites – Direct Market Participation

connected internally to site load information and one or more DER assets. External connections with various Internet sites, other DER*S equipped sites, the CalPX, the local UDC, an ESCO and/or a schedule coordinator are all possible. Market participation could be either via the CalPX, another SC indirectly via an ESCO.

In this scenario, the DER*S agents would have to balance site loads and costs against the potential return of bidding into one or more of the competitive markets. For instance, if high ancillary service pricing is predicted then bidding of standby generator capacity or curtailable load(s) could be justified. At this point, it appears unlikely that DER generation assets would bid into the bulk power market (CalPX) since generating power to offset local energy use (at the higher local rate) would provide greater benefit. However, bidding into one or more of the ancillary services (AS) markets may be justified in light of the volatility of these markets and the potential for high short term returns.

2.2 DER*S Capabilities

While it is not yet possible to fully define DER*S capabilities it is possible to infer some of the most likely capabilities based on our three basic operating scenarios. These capabilities can be divided into two categories where the first category contains essential capabilities and the second contains capabilities that could improve product performance or market acceptance (e.g., “bells and whistles”).

Basic DER*S Capabilities

The seven basic capabilities considered essential to DER*S product viability are:

- Monitor and Forecast DER Asset Performance / Output
- Monitor and Forecast Site Load (energy and demand) Requirements
- Monitor and Forecast Relevant Market Pricing
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- Graphical User Interface (GUI)
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- Communicate with External Entities (i.e., Internet, DER controls, etc.)

Additional DER*S Capabilities

Additional capabilities that would improve DER*S product performance or market acceptance are primarily related to automation of various aspects of DER*S-DER operations. . These additional capabilities are:

- Automatic Retrieval of Routine Data
- Direct Connection and Dispatch of DER Asset(s)
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- Automatic Verification / Resolution of Settlement Statements (if applicable)

3.0 California's Competitive Market[1]

The competitive market in California began operating on April 1, 1998. The California electricity market comprises approximately 10% of the total U.S. market representing roughly $22 billion in annual revenues and 246,000 GWh of annual energy consumption. About 70% of the total energy consumed in the California electricity market is provided by the three major investor-owned utilities (IOUs) (Southern California Edison, Pacific Gas & Electric, and San Diego Gas & Electric). The remainder is consumed in the service territories of municipal utilities and government entities.

3.1 Market Structure

Figure 4 shows the basic structure of the California competitive market(s) and the various entities involved in the production, distribution and use of energy in California. Additional information on the various market participants is provided in the following sections.

Customers (C)

Customers are end-users of energy in California and may be commercial, industrial or residential. All customers may choose direct access via a local utility or energy service provider (ESP) / Non-utility retailer. Energy service providers may aggregate customer loads to lower purchased power prices and transactions costs.

Generator / Supplier (G)

Generators / suppliers of power may bid into the spot market maintained by the California Power Exchange (CalPX) or schedule power deliveries directly with the California Independent System Operator (CAISO) using a Scheduling Coordinator. Using a Scheduling Coordinator, generators may also bid ancillary services into the California ISO or self-provide these services. Suppliers may have contracts with retailers and respond to CAISO instructions for unit operation provided by the Scheduling Coordinator or directly by the CAISO (depending on the nature of the service provided).

Retailer / Energy Service Provider (ESP)

Non-utility retailers / Energy Service Providers purchase power for, and market power to retail customers. ESPs may serve as demand aggregators for retail loads and schedule load and generation with the CAISO through a Scheduling Coordinator or the CalPX.

[1] This description is based on information provided in a recent report by the Market Monitoring Committee Of the California Power Exchange titled "Report on Market Issues in the California Power Exchange Energy Markets" by Roger E. Bohn et al. This report was prepared for the Federal Energy Regulatory Commission and issued on August 17, 1998.

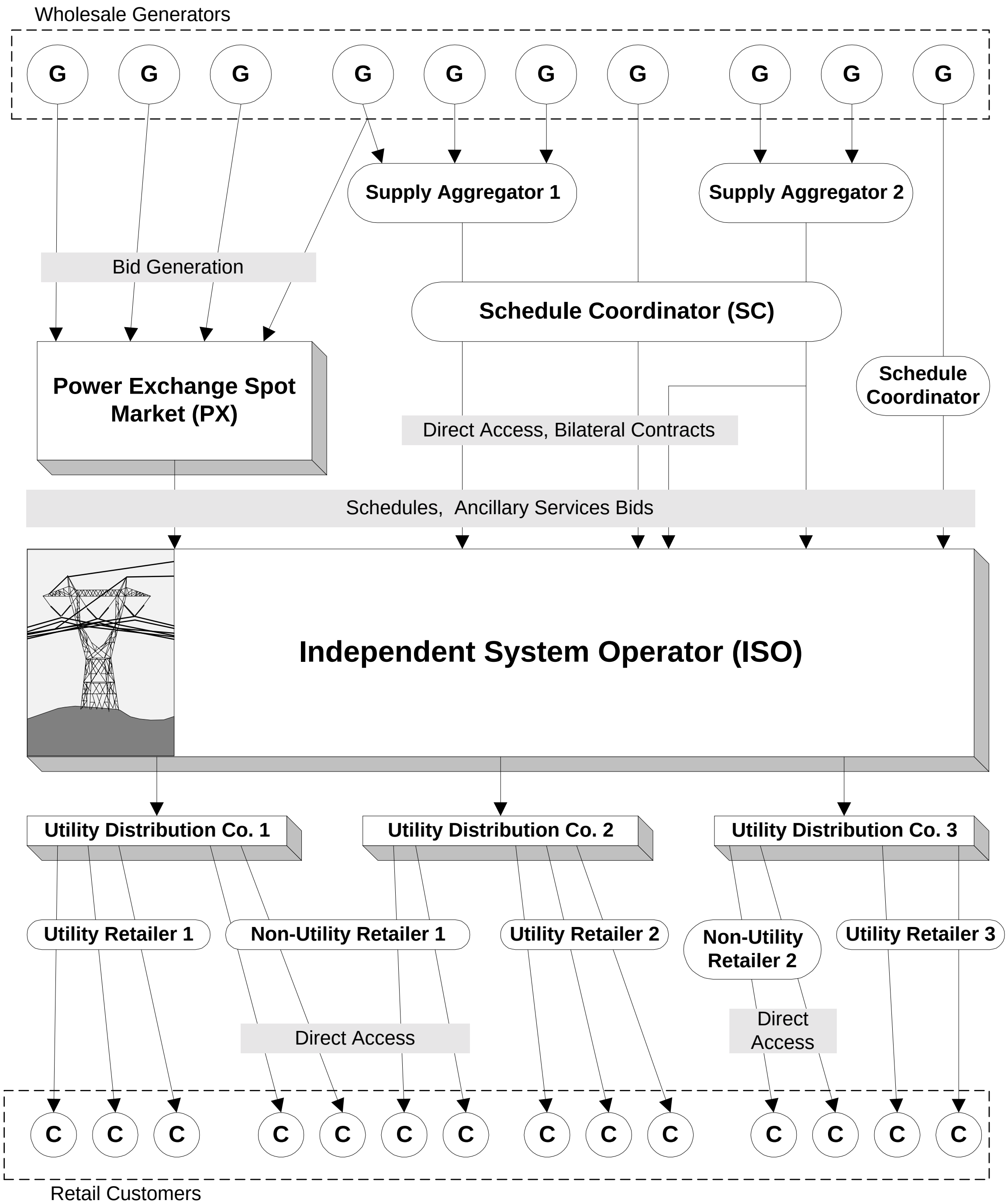

Figure 4 - California Competitive Market Structure

Scheduling Coordinator (SC)

SCs submit balanced schedules and provide settlement ready meter data to the CAISO. SCs settle with generators and retailers, the CalPX and the CAISO; maintain a year round twenty-four hour scheduling center and provides CAISO operating instructions to generators and retailers, transfer schedules in and out of the CalPX.

Utility Distribution Company (UDC)

The Utility Distribution Company maintains the electric distribution system within their individual service areas. UDCs provide distribution service to all customers within their service territory and are responsible for the sale of energy to all customers not classified as "direct access" customers (e.g., customers that contract with Retailers / Energy Service Providers). UDCs must supply all of their energy needs (sell generation into and purchase energy from) via the spot market maintained by the CalPX.

California Power Exchange (CalPX)

The California Power Exchange is a non-profit corporation that was formed for the primary purpose of providing a non-discriminatory, competitive energy auction open to all suppliers and spot-market purchases. The CalPX manages two forward energy markets (day-ahead, day-of[2]) and one demand market (block forward). Since the market opened, the CalPX has accounted for roughly 88% of the restructured California electric energy market. CalPX participants number approximately 45 and include UDCs, Federal and municipal entities, independent power producers, and ESPs, from both inside and outside of California. Based on the outcome of its day-ahead energy market the CalPX determines the Market Clearing Price (MCP) at which energy is bought and sold (excluding transmission congestion costs).

In addition to managing the forward markets the CalPX acts as an SC and submits balanced schedules to the CAISO for all of its participants and may act on behalf of its participants for submittal of bids into the CAISO ancillary services and imbalance energy markets. As a SC the CalPX performs settlement functions with the CAISO and CalPX participants, and reports usage to the CAISO for settlement purposes.

California Independent System Operator (CAISO)

The California Independent System Operator is a non-profit corporation tasked with maintaining a secure and reliable power supply in California. The CAISO controls the dispatch of generation and manages the reliability of the transmission grid while providing open access to the transmission system assets. The CAISO coordinates day-ahead, hour-ahead / day-of schedules and performs real-time balancing of load and generation using assets obtained in its ancillary services, imbalance energy and

[2] The CalPX originally maintained an hour-ahead market that was subsequently changed from 24 hourly auctions to 4 daily auctions with a corresponding name change from Hour-ahead to the Day-of market.

transmission congestion management markets. The CAISO does not own transmissions assets but does administer congestion management protocols for the transmission grid.

In addition to the Ancillary Service markets, which operate through an hourly market-clearing auction process, the CAISO also is responsible for acquiring Voltage Support/Reactive Supply and Black Start capability, which it procures through a longer term contracting process.

3.2 Restructured Market Operation

The restructured market continues to evolve as experience is gained and lessons are learned. It should be noted that changes have already occurred in the CalPX markets and the CAISO is currently examining ways to modify the markets that it operates[3]. The following discussion therefore pertains to the state of the restructured market at the time of writing. In its current state, the restructured market actually consists of five (6) separate but related markets operated by the CalPX and CAISO. The CalPX operates three forward markets (Day-ahead, Day-of and Block Forwards) for the sale of energy. The CAISO operates three markets (ancillary services, energy imbalance, transmission congestion) associated with its primary task of maintaining system reliability.

CalPX Market Descriptions

The CalPX operates three separate forward energy markets (Day-Ahead, Day-Of and Block Forwards markets). When the restructured California market first opened on April 1, 1998 the CalPX operated only its Day-Ahead energy market. Operation of an Hour-Ahead market began on July 3, 1998 and continued until January 17, 1999. On that date the Hour-Ahead market changed to the Day-Of market and the number of trades per day was reduced from twenty-four to three.

Day-Ahead Market

Each day by 7:00 a.m. CalPX Participants submit portfolio bids to buy and sell energy for each hour of the succeeding day. These portfolio bids are used by the CalPX to derive aggregate supply and demand curves. Using these curves the CalPX establishes an unconstrained market clearing price and quantity for each hour and identifies the successful bidders. Following the conclusion of the Day-Ahead auction, successful bidders must then provide the CalPX with specific information relative to their initial portfolio bid (quantity and location of loads and supplies within the grid) in the form of an Initial Preferred Schedule. The CalPX, along with other SCs provides these schedules (which are balanced with respect to supply and demand in each hour) to the CAISO. These schedules also include Participants' Ancillary Services Bids and Schedule Adjustment Bids.

[3] This topic is covered in more detail in the "Market Surveillance Committee of the California Independent System Operator - Report on Redesign of Markets for Ancillary Services and Real-Time Energy" by Frank Wolak, et. al., March 25, 1999.

Having received schedule and associated bid information from all of the SCs (including CalPX) the CAISO then conducts its Ancillary Services market/auction and performs congestion management. Adjustments, if needed, are made to the initial preferred schedules and these suggested changes are provided to the SCs. The CAISO receives updated schedules from the SCs and issues Final Day-Ahead schedules including Ancillary Services requirements by 1:00 p.m. on the day prior to the day of delivery. The CAISO also publishes the final transmissions usage charge rates if transmission congestion has occurred. Using this information, the CalPX then calculates the Zonal Market Clearing Prices.

<u>Day-Of Market</u>

In the Day-Of market, buyers and sellers are able to adjust the positions they received in the Day-Ahead market in order to minimize real-time imbalances. Changing weather conditions or supply changes due to plant outages or line de-ratings can all result in a need for adjustment of the Day-Ahead schedule. In the original Hour-Ahead market, bids (unit specific bids) were submitted at least 2 hours before the hour of operation with a total of twenty-four hourly auctions each day. At the request of market participants this was changed to just three auctions per day occurring at 6 a.m., noon and 4 p.m.

The CalPX determines the MCP in the same way as the Day-Ahead Market and communicates price and traded quantities to participants immediately after the Day-Of market is closed.

<u>Block Forwards Market</u>

A CTS (CalPX Trading Services) Block Forwards Market contract is a standardized contract for delivery of on-peak (6 a.m. – 10 p.m., Monday through Saturday) energy during a calendar month. The contract provides for delivery of a specific amount of on-peak energy to a California delivery point. Trading of CTS Block Forwards Market contracts occurs each weekday from 6 a.m. – 10 a.m. when participants telephone the CTS trading desk to submit orders (bids and offers). The trading desk provides best bid and offer information and matches trades in a continuous bid and offer process.

CAISO Market Descriptions

The CAISO maintains three markets directly related to its primary task of maintaining system reliability. The Ancillary Services market provides the CAISO with sources of regulation, spinning reserve, non-spinning reserve and replacement reserves while the Imbalance Energy market enables the CAISO to "trim" resources to maintain the system-wide energy balance. The Transmission Congestion Management market facilitates CAISO management of inter-zonal transmission congestion.

<u>Imbalance Energy Market (Real-Time Market)</u>

The CAISO is responsible for balancing loads and resources in real-time in order to maintain a high quality and reliable supply of energy. To accomplish this requires that the CAISO be able to increment and decrement resources as needed to maintain a system-wide energy balance. The CAISO uses bids received in the Imbalance Energy market to determine the most cost-effective way to achieve this goal. Imbalance Energy market bids include Supplemental Energy Bids, which Participants provide to the CAISO up to one hour prior to the dispatch hour, as well as the energy bids submitted by Participants in conjunction with their Ancillary Services capacity bids (as described below). The Imbalance Energy market price is calculated in 10 minute intervals and price is used to settle deviations between scheduled and actual quantities of supply and demand. A Participant that over-delivers relative to its scheduled quantity is paid the imbalance price, while a Participant that under-delivers relative to its scheduled quantity is charged this price.

Ancillary Services Markets

The Ancillary Services market actually consists of four day-ahead and four hour-ahead capacity auctions. These auctions provide for CAISO access to generation capacity needed to insure reliable system operation. The four basic ancillary services covered by these auctions are: Regulation, Spinning Reserves, Non-Spinning Reserves, and Replacement Reserves. Unlike the energy markets operated by the CalPX, each of these markets is for capacity only[4]. Bids into the Ancillary Services market are relayed to the CAISO by Scheduling Coordinators along with the Day-Ahead schedule information.

Transmission Congestion Management

The Transmission Congestion Management market operates using Schedule Adjustment Bids (SAB) that are provided to the CAISO by SCs. SABs are basically the cost (to the CAISO) to increase or decrement a resource depending on price. As such SABs indicate the willingness of a SC to increment a resource based on price, and are an expression of the value that the SC places on obtaining inter-zonal transmission access. The CAISO uses SAB values to adjust individual resource schedules in order to relieve congestion and to subsequently calculate transmission congestion Usage Charge rates.

3.3 Electric Distribution Operation, Cost and Performance Opportunities

UDCs are regulated monopolies within the restructured electric market. The UDC's primary function is to provide reliable electric distribution services to all customers, including those with direct access, within its service territory. Broadly speaking, "distribution" includes all parts of an electric utility system between the point of bulk power delivery and the consumer's service entrance. Utilities typically design distribution feeders to operate in the range of 4.16 to 34.5 kV to supply load in a well-defined geographical area. Distribution system planning and design involves complex methods of load forecasting, circuit analysis and applied engineering economics.

[4] Each bidder must also submit an energy bid along with the ancillary service bid. The Energy Bids in the Regulation market are used for validation only while the Energy Bids for Spinning, Non-Spinning, and Replacement Reserves are used, along with Supplemental Energy bids, in the real-time Imbalance Energy market.

Distribution systems consist of breakers, conductors, transformers, fuses, capacitors, switches, monitoring and control systems, communication systems, above and underground structure assets. Figure 5 illustrates a typical primary distribution feeder.

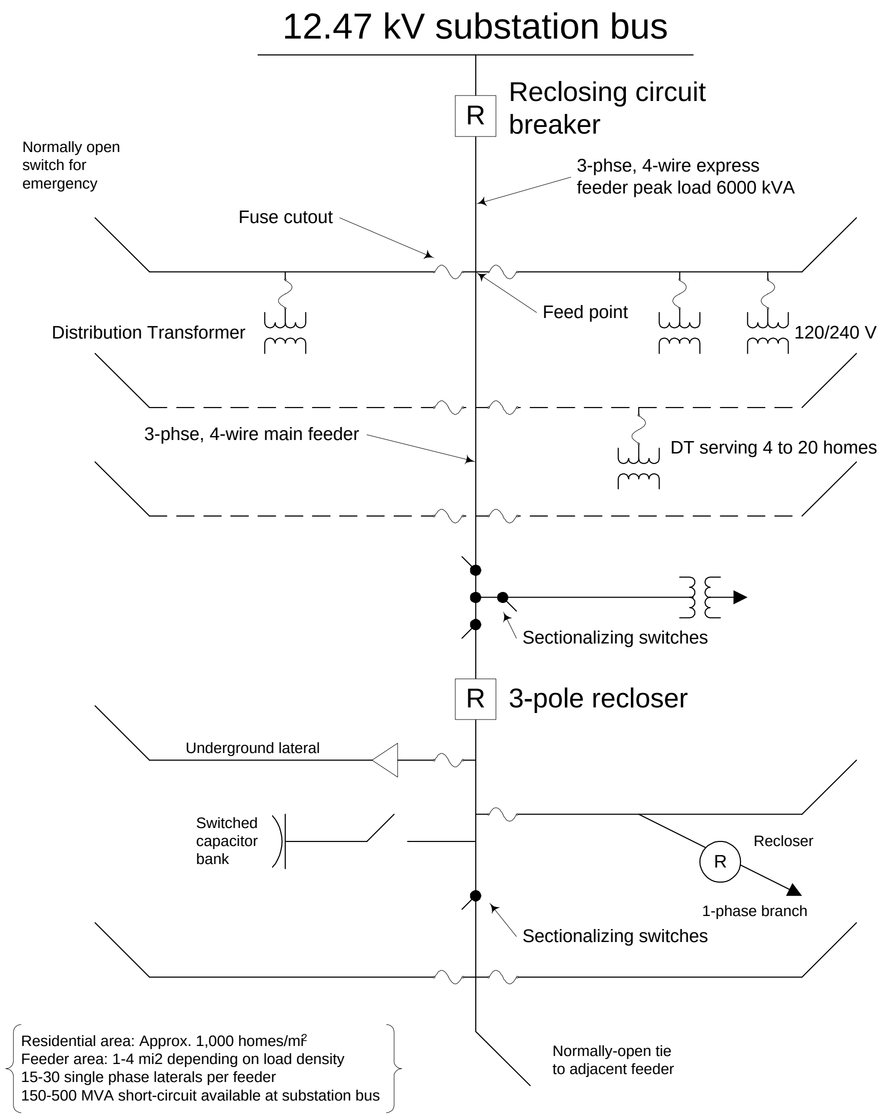

Figure 5 - One-line diagram of typical primary distribution feeder[5]

There are several considerations affecting distribution system planning: regional load growth, voltage, reliability, etc. Distribution planners have at their disposal a number of design options to meet specific situations. More specifically they can choose between radial and loop feeder design philosophies. Their ultimate goal is to meet service requirements at the lowest cost possible. However, reaching this goal is further challenged by the regulatory and economic environment changes resulting from electric market restructuring.

[5] Reproduced from Fink and Beaty, Standard Handbook for Electrical Engineering, Eleventh Edition.

Recently the California UDCs have filed for performance based ratemaking (PBR) mechanisms for distribution service. In the SDG&E PBR filing decision the CPUC indicated the intent of PBR.

> We have long considered incentive-based ratemaking superior to command-and-control regulation. PBR rewards the UDC for achieving improved reliability at lower costs. PBR sends an important message to the UDCs that minimizing costs without sacrificing service quality and reliability can result in greater rewards with "less" regulation than traditional cost-of-service.[6]

PBR requires the establishment of a baseline revenue requirement for distribution service. Baseline revenue requirements are adjusted annually for inflation and productivity changes. Decreases in adjusted revenue requirements, that exceed a pre-defined range, result in an increase in stockholder earnings as long as various performance indicators do not deteriorate.[7] The performance indicators include; safety, reliability, customer satisfaction, call center responsiveness and certain customer service guarantees. Specifically reliability performance indicators include; system average interruption duration index (SAIDI), system average interruption frequency index (SAIFI) and momentary average interruption frequency index (MAIFI).

Several studies have identified power delivery cost and performance benefits derived from DER installations. Past studies by the Electric Power Research Institute (EPRI), Pacific Gas and Electric (PG&E) and others have identified benefits including; capital deferral, reduced energy loss and improved reliability. It appears that a direct connection exists between the DER potential benefits and UDC PBR mechanisms.

3.4 Electric Pricing / Retail Rates

Any discussion of the California competitive market would be incomplete without some discussion of how the new market affects the customer's bill for electricity. This is especially important in discussions related to DER operations since DER equipment has historically been owned or operated by customers whose primary contact with the competitive market is their monthly utility bill. Figure 6 shows the various entities and associated cost elements that impact an electric utility bill in the California electricity market.

As the figure shows the wholesale base price of electricity is the base upon which a large number of fees/charges are attached before electricity is ultimately delivered to the customer. These fees/charges are not unjustified since each represents payment for a service that is provided in order to eventually deliver the electricity to the customer. Some of the fees associated with an electricity bill are fixed while others are based on consumption (e.g., distribution and transmission charges, etc.). While we have tried to show the various cost adders on the figure it should be noted that not every fee is applicable for every customer. For instance, electricity provided to a residential customer

[6] CPUC Decision 99-05-030, "Application of San Diego Gas & Electric Company (SDG&E) for Authority to Implement a Distribution Performance-Based Ratemaking Mechanism", Filed January 16, 1998, Decided Many 13, 1999.

[7] Conversely, earnings can decrease when adjusted revenue requirements increase.

by the local UDC would not be subject to aggregator's fees or the fee of a separate SC. It is not our intent to define specific charges for different customers but to show that the price ultimately paid by the customer is significantly higher than the base electric price, with many of the fees tied directly to consumption.

So it can be seen that DER operation has the potential to provide benefits at both the retail (e.g., off-setting customer electric costs) and wholesale levels (e.g., sale of energy or capacity into one of the six competitive markets). How DER benefits are achieved and specifically what role the DER*S product would play in this process is a fundamental question that must be addressed before the DER*S product can be fully defined. We will address these issues in more detail in our discussion of DER benefits in Section 4.

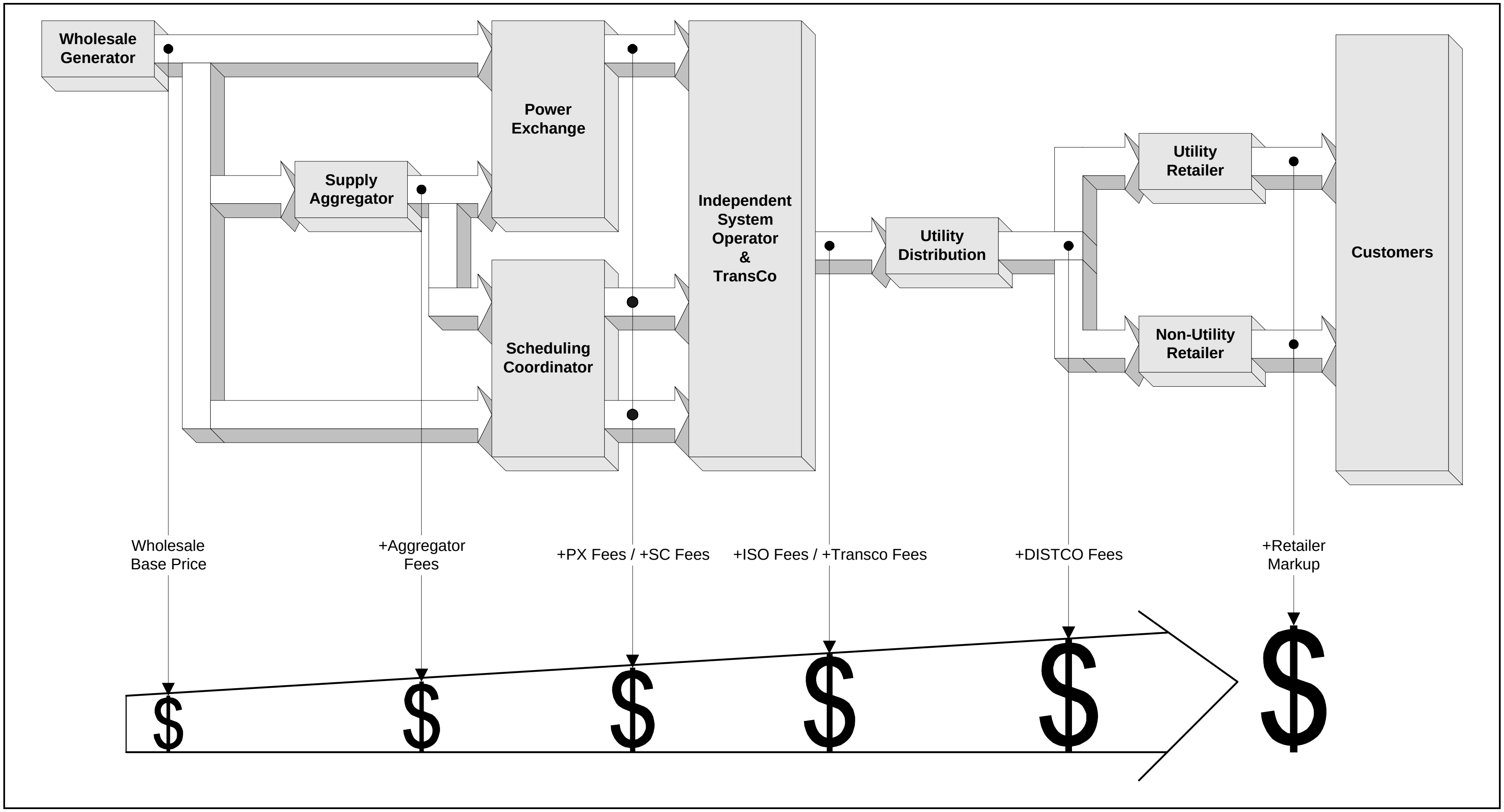

Figure 6 – Electric Price / Cost Contributors

4.0 DER Technology Description

This section provides an overview of DER technologies, their characteristics and their likely applications. A description of the DER technology characteristics and applications are useful in understanding the domain within DER will be applied and operate.

4.1 Definition of DER

The definition of DER is crucial in understanding technologies and applications that fit within its operational domain. At initial glance, a DER definition appears to be easily established. However, even a light treatment of details reveals multiple attributes of DER that are not easily established or agreed. The difficulty is rooted in the many related forms of DER (e.g., cogeneration, distributed generation, distributed utility etc.) some of which are defined only in close circles while others have well established public, albeit non-standard definitions.

For purposes of this project, we adopt a broad definition of DER whose essential characteristic is proximity to load. In this definition we do not limit DER capacity size and include end-use load management through energy efficiency and demand shifting. Later in this report, we will discuss the subset technologies and applications within the DER definition that are likely candidates for DER*S. the adopted DER definition, which is adapted largely from the California Alliance for Distributed Energy (CADER) is summarized below in Table 1.

Table 1 - Distributed Energy Resource Definition

Definition of DER
❖ Generates, stores or conserves electricity
❖ Located near or at a load center
❖ Can be grid connected or isolated
❖ Has a value greater than grid power including –
– Customer value
– Power delivery benefits
– Social or environmental value

4.2 DER Technology Classifications

DER technologies can be classified three broad categories: electric generation, energy storage and energy efficiency. We have further segmented each broad category into smaller categories that are more detailed. Table 2 provides a breakdown of the various DER categories.

Table 2 - DER Technology Classifications

❖ Electric Generation – Fossil Fuel ▪ Gas Turbines (GTs) ▪ Fuel Cell Power Plants ▪ Internal Combustion Engine/Generators (ICEs) – Renewable Fuel ▪ Photovoltaic Systems (PVs) ▪ Solar Thermal Electric ▪ Wind Turbines ▪ Small Hydro	❖ Energy Storage – Batteries – Flywheels – Thermal Energy Storage ❖ Energy Efficiency – Lighting – Motors – HVAC&R – Industrial Processes – Office Equipment ❖ Demand Side Management – Curtailable Loads

*4.3 DER Technologies Most Applicable to DER*S*

The DER*S technology, once developed, will be a sophisticated scheduler for distributed energy resources. DER*S is applicable to DER equipment that can be dispatched. Non-dispatchable technologies, such as wind, solar, and energy efficiency, are not compatible with DER*S because their production output is not easily controlled. However, in some DER technologies, the addition of energy storage *can* provide dispatching capability. Note that curtailable loads can be dispatched depending on the type of load involved. For example, air conditioner cycling by remote control is a dispatchable resource that could be bid into the ancillary services market as non-spinning reserve (available within 10 minutes). Loads (i.e., process loads, requiring additional advance warning could still be classified and scheduled/dispatched as replacement reserves (available within 60 minutes). Other DER technologies such as ultracapacitors and SMES provide short bursts (i.e., milliseconds) of electric energy to improve power quality. Although dispatchable these technologies are triggered by power quality events and do not affect the aggregate value of electric energy. Table 3 summarizes DER technologies that are dispatchable and, therefore, most compatible with DER*S.

Table 3 - DER Technologies Compatible with DER*S

DER Technology	Notes
Gas Turbines (GTs)	Generally dispatchable, but may be designed to operate as base load cogeneration or combine cycle. In DER base load operation, dispatch is not an option because the plant is constantly at maximum available output.
Fuel Cell Power Plants	
Internal Combustion Engine/Generators (ICEs)	
Photovoltaic Systems (PVs) w/ energy storage	Generally not dispatchable. However, the addition of energy storage or combining with other generating technologies can provide dispatching capability.
Solar Thermal Electric w/ co-firing capability and/or energy storage	
Wind Turbines w/ energy storage	
Small Hydro	Dispatchable, but is constraint by availability of sufficient hydro head.
Batteries	All energy storage is inherently dispatchable.
Flywheels	
Thermal Energy Storage	
Load Management / Curtailable Loads	Some curtailable loads such as air conditioner cycling is dispatchable while other loads require some advance notice. Loads requiring advance notice may be scheduled or bid as ancillary services (i.e., non-spinning reserve, replacement reserve)

4.4 DER Controls

In this project we are most interested, in the DER external interface controls that deal with DER unit commitment and dispatch. The various DER equipment types have numerous controls for internal process functions and external interface requirements. The nature and complexity of internal controls are dependent on the type of DER equipment. For example, internal combustion reciprocating engine generators have internal controls for fuel, air, ignition, cooling and electrical systems that provide shaft speed regulation, generator loading, engine thermal management, and other functions.

External interface controls are those systems that monitor and react to changes in the way the DER operates relative to external conditions. For example, fuel control pressure regulators in an engine or gas turbine must compensate for changes in natural gas supply pressure. Another example is electric grid interconnection operation and protection, which is important to all grid-connected DER technology applications.

A special subset of external interface controls are those that deal with DER unit commitment and dispatch. "Unit Commitment" is a decision to start a generator or storage system to serve a load. "Dispatch" means bringing the committed DER unit to a specific load point to minimize cost or maximize benefits. Historically, utilities have used these terms to describe central power plant operation in the bulk power markets. Industry has used these terms sparingly when talking about DER technologies. However, we find for purposes of this development project that these terms are appropriate when discussing DER scheduling and loading for net benefit maximization.

The control logic for the commitment and dispatch of DER assets is dependent on the nature of the DER application and designed service. We have summarized the typical types of DER service below.

1. *Emergency/Backup* - In this service, DER equipment remain in standby mode until needed to replace loss of grid supply. Commitment controls for this type of service require sensors to detect loss of grid and/or sudden voltage or frequency excursions. In many applications, time to start, stabilize and serve load is critical. For this reason, smaller load applications may use battery energy storage alone and larger applications may integrate engines and gas turbines with quick starting battery or flywheel energy storage devices to provide a complete uninterruptible power supply (UPS) system. These DER systems typically serve critical dedicated customer circuits that are isolated with automatic transfer switches. Dispatch controls are designed to fully service the dedicated circuits by load following. Because they operate isolated from the grid, interconnection and synchronous operation are not as much an issue as those DER that operate grid connected. This mode is also applicable to energy storage DER technologies.

2. *Peak Shaving* - This DER application serves to control the cost of electric energy by limiting the customer's net power consumption during relatively short periods of time. In many peak shaving applications, unit commitment is a function of time dependent electric rates (e.g., time-of-use or real-time pricing) and/or ratcheted demand charges. Utilities can also use peak shaving as a way to reduce excessive loads in stressed areas of their grids. This *load* clipping application is different from *price* clipping, but we consider both as forms of peak shaving service. The main difference between these two is the external signal that triggers the commitment of these DER units. Load clipping is a function of the magnitude of the local distribution load while price clipping is a function of the price of electricity. Dispatch control for these applications typically means bringing the DER unit to maximum output for the duration of the need. This mode is applicable to energy storage DER technologies.

3. *Load Following* - DER equipment operating in this mode are trying to maximize their capacity factor without exceeding local electric load resulting in unwanted power export or when a cogenerator is following thermal load so excess heat is not dumped. Load following is likely when excess power or heat decreases the economic attractiveness of the DER operation. Commitment control logic is trivial since the intent is to run the unit as much as possible unless local load goes completely to zero. Dispatch control requires following of local load without reversing power flow or producing excessive heat. This is applicable to storage DER technologies only when coupled with under sized dispatchable generator or non-dispatchable renewable generator such as wind or photovoltaics.

4. *Constant Loading* - Also known as base load operation, this DER operating mode sets the generator output at full power constantly. Many PURPA cogenerators are designed to operate this way. When the electric output of the cogenerator exceeds the local load, power is sold into the grid at utility avoided costs. In constant load operation, both unit commitment and dispatch control is trivial.

Aggregated operation for grid support is a special DER operating mode that can incorporate multiple DER assets at different sites. In recent years both hardware and software products have become available that allow for remote / centralized control of multiple DER assets for grid support purposes. Utilities and ESCOs initially installed these control systems so that emergency back-up generators (manual switchover, grid-isolated operation, etc.) could be grid-connected and centrally dispatched. RTU hardware and software installed on a generator or other DER asset provides both grid interconnection and safety systems while allowing for remote communication and control of the DER. Software packages at the central dispatch point provide dispatch of single or multiple units grouped by a variety of parameters as well as direct access to individual unit operating parameters. Additional hardware provides information on operating parameters vital to the centralized dispatch (i.e., output, operating temperatures, etc.). These products have been promoted to UDCs for use as additional capacity as an extension of their existing interruptible rate programs but are also seeing use for aggregation and bidding into the California ancillary services markets.

4.5 DER Controls Most Applicable to DER*S

It is apparent from the various DER*S operating scenarios described in Section 2 that communication with, and remote control of the DER asset(s) is essential to DER*S operation. Therefore, DER controls that provide remote communications and connectivity are more readily adapted to the DER*S approach. In addition, controls that provide safety features, grid interconnection and other fundamental unit operating requirements (i.e., cooling, lubrication, fuel control, etc.) would relieve the DER*S agency from providing these control functions. These intrinsic controls, by necessity, require fast response times and are typically handled by analog or high-speed digital controls. Scheduling and dispatch functions, on the other hand, do not have the same rapid response requirement. Thus, control of these high-speed functions outside of the DER*S agency would allow use of more conventional computing resources. Table 4 summarizes these and other characteristics that facilitate DER*S integration.

Table 4 – DER Control System Characteristics Compatible with DER*S

DER Control System Characteristic	Notes
Control of basic/intrinsic DER operating parameters (safety, grid-interconnection, cooling, lubrication, etc.)	These intrinsic DER functions are separate from the DER*S scheduling and dispatch functions.
Remote communications and control capabilities	Facilitates implementation of DER*S scheduling and dispatch instructions.
Compatible with a variety of building energy management systems (EMS)	Facilitates DER*S access to multiple on-site DER assets as well as sensors (i.e., ambient temperature, building load, etc.) and interfaces already connected to a site EMS.
Open software design allowing integration of 3rd party software modules.	Facilitates integration of DER*S software modules into the existing controls. Improves DER*S retrofit capability.

See Appendixes A and B for additional sample information on current DER control (OEM) and 3rd party control software products respectively.

4.6 DER Benefits

The type of benefit derived from DER applications depend on the beneficiary's perspective. A utility customer receives different benefits than a Utility Distribution Company, energy service provider or independent system operator. Indeed, the motivation for DER application is different for each market player. We have summarized potential benefits from DER application from each market player's perspective in Table 5 below.

Table 5– Summary of DER Benefits

Beneficiary	Potential DER Benefit
Energy Customer	Lower overall energy costs and increased power supply reliability. DER can accomplish this by supplying electric and thermal energy supplied locally to a customer or group of customers, or reducing the PX price of electricity to all customers by reducing system wide load.
Energy Services Company	Bundling of customer on-site DER services with power and fuel contracts to increase customer value and improve contract margins. DER can serve as an as arbitrage machine for customer electric supply or improve aggregate customer load shape to enhance power purchases.
Electric Distribution Company (regulated)	Improved power delivery reliability/efficiency, active line reactance control, asset utilization and deferment of infrastructure capital investment. Under PBR mechanisms UDC shareholders can profit by improved performance of the distribution system.
Independent System Operator (regulated)	Congestion relief and potential ancillary service resource.
Gas Distribution Company (regulated)	For natural gas fueled DER, increased natural gas fuel sales and improved asset utilization.

DER can be applied such that it is dedicated to one of these beneficiaries or interact with a number of beneficiaries. Figure 7 further illustrates the possible interactions that DER may have with various beneficiaries.

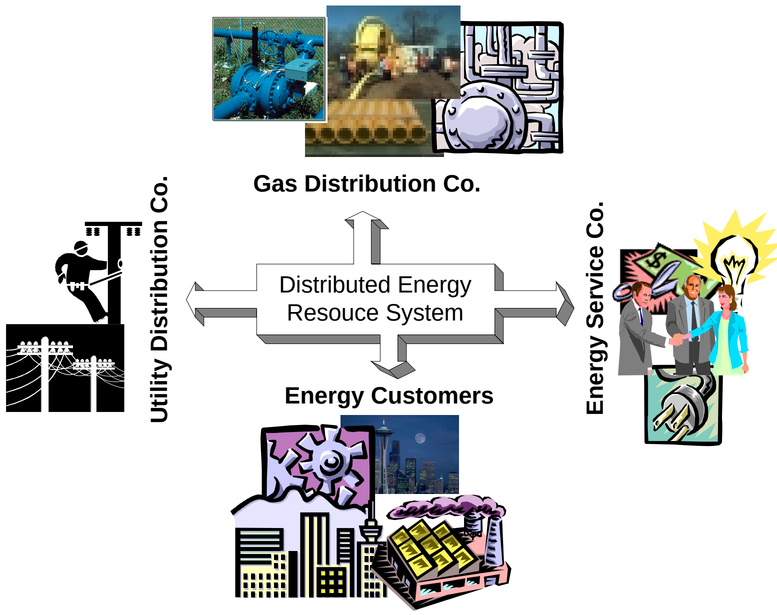

Figure 7 – DER – Beneficiary Interaction

How DER benefits flow to beneficiaries and *who* is paid for the benefit is dependent on DER ownership and the market involved. For example, strategically located DER may supply vital ancillary services through the ISO, which benefits all electric customers. The payments for this service would flow to the owner of the DER, which may be a customer, ESCO or even an UDC. Not all benefits receive payments. An example of this would be the reduction of PX electric price resulting from load reduction that benefits all electric customers that purchase from the PX. The cause of the reduction may be the operation of customer DER that reduces the net load to the grid.

4.7 DER Technology Characteristics

DER technology characteristics are discussed below.

Internal Combustion Engine/Generators (ICE)

ICE (a.k.a. reciprocating engine) generators have a long history as standby and remote electric generating plants. In the early 1970's ICE's become popular for cogeneration plants typically below 1 MW in capacity. ICE power plants are available from 50 kW to 5 MW capacity sizes in diesel and spark ignition configurations. They are primarily fueled with natural gas, diesel and gasoline. Some ICE plants are fueled with anaerobic digester gas, landfill gas and there are developments for coal fueled ICE power plants. An ICE cogenerator located in Chino, California is shown in Figure 8.

Figure 8 – 625 kW ICE Cogeneration Unit

Gas Turbines (GTs)

GT/generators are modified jet engines used for stationary electric generation. Simple cycle GT power plants come in wide range of sizes. Large GT plants can be as large as 200 MW in capacity and are popular in new combine cycle power plants. Medium size GTs range from 10 MW to 80 MW and are most popular in larger industrial cogeneration plants or partial repower projects. Small GT plants range from 1 MW to 10 MW in size and are used in industrial and large commercial cogeneration applications (see Figure 9). The newest GT power plant systems are microturbines that range from 25 kW to 500 kW in size (see Figure 10). Some GTs in the small to medium range are aeroderivative engines that have been adapted from jet aircraft engines. GTs are know to have a relatively high thermal to electric production ratios and can produce high temperature steam which makes them well suited for large thermal host applications.

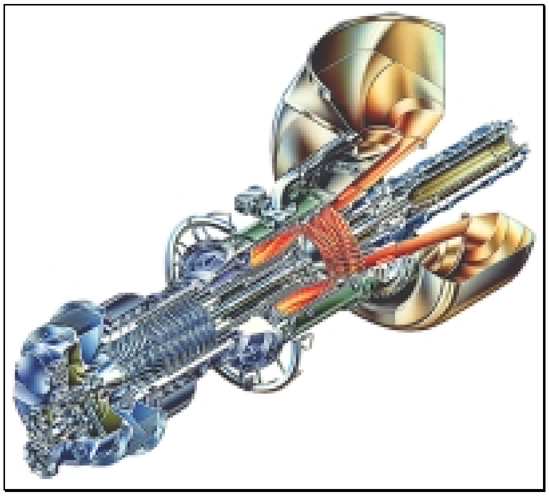

Figure 9 – Solar Turbines Centaur Gas Turbine

Figure 10 – Allied Signal 75 kW Microturbine

Fuel Cells

Fuel cells produce direct current electric power by combining fuel and oxidant in an electrochemical reaction. An inverter is used to convert the DC power into AC power that is compatible with the grid and/or load. There are five major types of fuel cells; phosphoric acid (PAFC), molten carbonate (MCFC), solid oxide (SOFC), proton exchange membrane (PEM) and alkaline fuel cells. The type of electrolyte used in the cell stack differentiates them. Alkaline fuel cells are used exclusively for aerospace applications such as the space shuttle. PAFC's are the most mature of the stationary fuel cell power plant technologies. PEM's are being developed for transportation and stationary applications. SOFC's and MCFC's are currently in development and demonstration stages. Fuel cells are fueled primarily with hydrogen[8]. Fuel processors are used to convert raw fuels, such as natural gas, into hydrogen rich fuel streams using steam reformation or partial oxidation processes. PAFC's have been operated on renewable fuels like landfill and digester gas.

Future advancements include multi-fuel processors allowing a wide variety of fossil fuels to be used for fuel cell power plants. Smaller fuel cell power plants targeted for residential and small commercial customers are being developed by Plug Power, a joint venture between Detroit Edison and Mechanical Technology Inc. They are currently in the demonstration phase of 5-10 kW fuel cell generators.

Figures 11 and 12 show examples of fuel cell power plants.

Figure 11 – ONSI 200 kW PC-25C Phosphoric Acid Fuel Cell Power Plant

[8] However, MCFC's and SOFC's have the capability of utilizing carbon monoxide as a fuel.

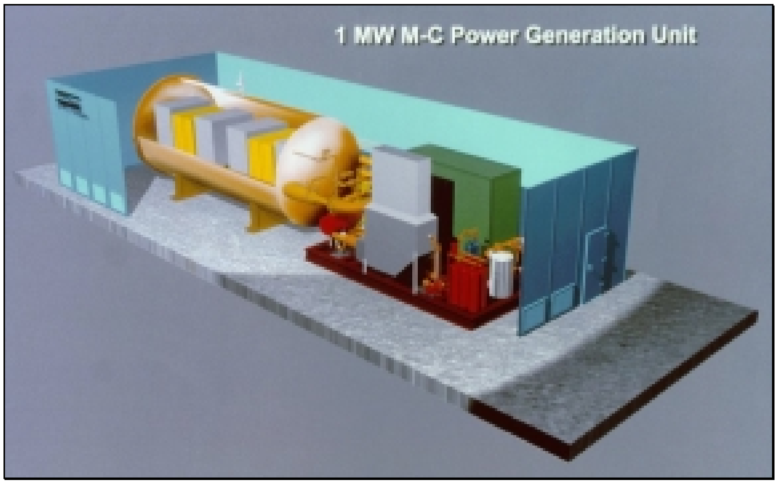

Figure 12 – M-C Power 1 MW Molten Carbonate Fuel Cell Power Plant

Photovoltaic Systems

Photovoltaics (PVs) convert solar energy directly into direct current electricity. Individual PV modules are commercially available in sizes from 10 W to 300 W. The actual power output may differ from module rated and depends upon the intensity (W/ft^2) of sunlight, the operating temperature of the module, and other factors. Additional electrical power conditioning components are required to interface the PV with the electrical load. Different semiconductor materials and techniques are used to fabricate PV cells. Some common types of cells include single-crystalline silicon, semi- or poly-crystalline silicon, thin-film crystalline and amorphous silicon cells. Tracking devices may be used to enhance the capture of sunlight energy. Compared to other modular generating technologies, such as fuel cells or ICE generators, PV systems require relatively large areas to obtain significant amounts of power. A typical one square meter flat panel PV system has a generating capacity of 50 W to 150 W assuming 1 kW/m^2 of incident solar radiation.

Figures 13 and 14 show residential PV systems.

Figure 13 – Photovoltaic Panels on SMUD Residential Customer Home

Figure 14 – Home with Uni-Solar Photovoltaic Shingles

Solar Thermal/Electric

There are three major types of solar thermal/electric generators; solar power tower, solar parabolic trough and solar dish Stirling engine. The most likely of these that would be used for self-generation is the solar dish Stirling engine. Dish/engine systems utilize concentrating solar collectors that track the sun in two axes. A reflective surface of metallic coated glass or plastic reflects incident solar radiation to small region called the focus. The engine determines the size of the solar concentrator for dish/engine systems. A 25 kW dish/Stirling system's concentrator has a diameter of approximately 10 meters. Currently a dish/Stirling system is being developed and demonstrated by Science Applications International Corporation (SAIC). SAIC and Stirling Thermal Motors, Inc. (STM) are working on next generation hardware including a third-generation which includes a faceted stretched membrane dish with a face-down-stow capability and a directly-illuminated hybrid receiver. Dish/Stirling systems are considered the most efficient way of converting solar energy to electricity. Figure 15 shows the SAIC dish Stirling system.

Figure 15 – SAIC 25 kW Solar Dish/Stirling System

Wind Turbines

Wind energy systems generate electricity by converting kinetic energy from moving air into torque that drives a generator. The two basic types of wind turbines are the horizontal-axis wind turbine (HAWT) and the vertical-axis wind turbine (VAWT). HAWT's are the most common. They consist of: (1) rotor with two or three blades, (2) a drive train coupled with an electrical generator, and (3) a tower and foundation supporting the rotor and drive train. Supporting subsystems include controls, electric power transfer cables and step-up transformer. The use of a electronic power converter (inverters) permit variable speed operation of the wind turbine and finer control over power quality. About 70% of all installed wind turbines in California are rated at 150 kW or less (CEC, 1993). However, the overall trend in the United States is toward larger turbines in the 200 kW to 500 kW range. Sixty-eight percent of new wind capacity installed in California in 1992 was 200 kW or larger. While no megawatt-scale wind turbines are currently being developed in the United States, such research and development is active in Europe. A small wind 10 kW turbine is illustrated in Figure 16.

Figure 16 – 10 kW Bergey Wind Turbine

Energy Storage Technologies

Electric energy storage converts electricity into a form that can be stored for conversion back to electricity when needed. The conversion of electricity into the storable form is referred to as “charging” and the conversion of the stored energy into electricity is called “discharging”. Storage devices are distinguished by characteristics of the stored energy: batteries store electricity electrochemically: flywheels store energy in kinetically: and thermal energy storage stores energy as heat sources or sinks. Each technology has different characteristics in its power density, power capacity and energy capacity. The chart below (Figure 17) shows power and energy density of various DER technologies including energy storage.

Battery storage systems are common in small capacity sizes. Large MW size facilities are much more scarce and the technology is still in development for practical widespread use. Figure 18 illustrates a packaged battery storage unit for commercial and industrial applications.

Flywheel systems have promising applications in automobile and locomotive transportation. There has been some discussion of developing flywheel systems for commercial and industrial customer applications. Figure 19 shows a typical flywheel system.

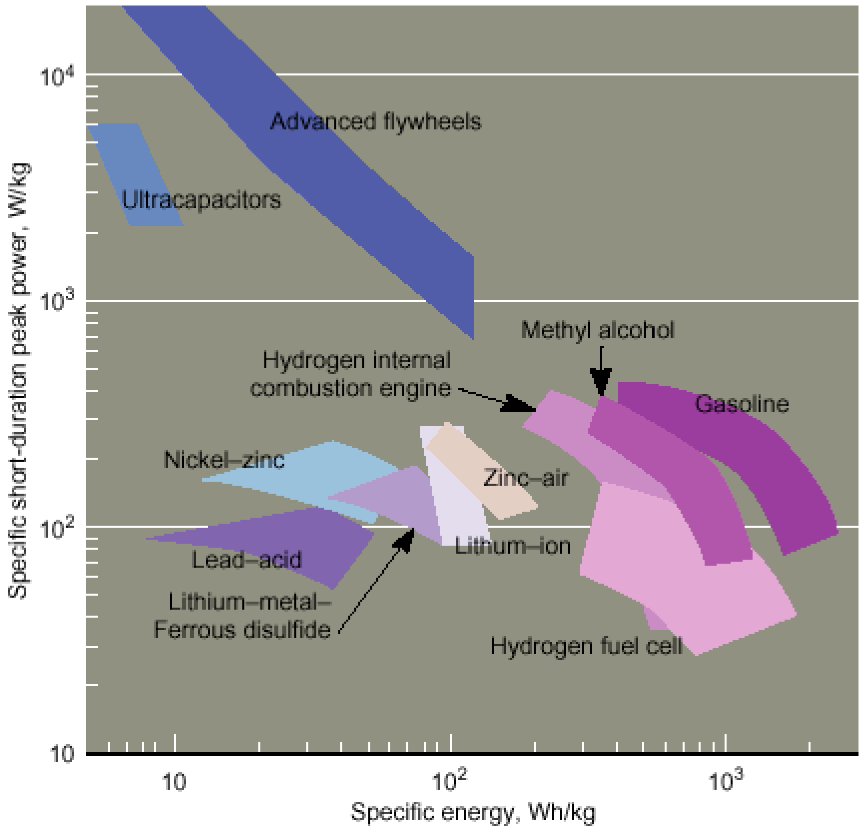

Figure 17 – DER Technology Power and Energy Densities

Figure 18 – Packaged Battery Storage System

Figure 19 – Example Flywheel Storage System

One method of thermal energy storage is to produce chilled water or ice during low cost off-peak electric rate periods and then use the heat sink during high cost electric rate periods to cool the customer's facility. Figure 20 shows a type of modular ice storage system used worldwide.

Figure 20 – Example Ice Storage System

Summary of Characteristics

The primary performance and cost characteristics of the various DER technologies are summarized in 6.

Table 6 – DER Technology Matrix

	DEVELOPMENT STATUS		OPERATION									
	Current Status (Dev, Demo, Comm)	Year Commercial	Rated Full Load Net Capacity (kWe)	Rated Minimum Load (%FL)	Useable Thermal Output (Btu/kWh)	Useable Thermal Temp. (F)	Operator?	Dispatch-able?	Practical Load Duty (Base, Interm., Peak)	Compatible Fuel(s)	Fuel Specifications	Cold Start-Up Time (minutes)
GENERATION												
Reciprocating I/Cs												
Diesel	Comm		50 - 5,000	50	3,400	185 - 900	No	Yes	B,I,P	Diesel	>2.0 psig	0.167
Otto (Spark Ignition)	Comm		50 - 6,000	50	1,000 - 5,000	316 - 500	No	Yes	B,I,P	Biogas, Natural Gas, Propane	1.0 - 45 psig	0.017 - 0.167
Gas Turbines												
Micro-Turbines	Dev/ Demo	1997 - 1999	25 - 250	0 - 50	4,000 - 15,480	400 - 635	No	Yes	B,I,P	Nat. Gas, Diesel, Propane, Multi-fuel	3 - 100 psig	0.5 - 1.0
Small Gas Turbines	Dev/Comm.	1999	500 - 10,000	5 - 50	3,400 - 12,000	500 - 1,100	No	Yes	B,I,P	Nat. Gas, Distillate, Biogas	140 - 500 psig	1.0 - 10.0
Fuel Cells												
Molten Carbonate	Demo	2000 - 2003	250 - 2,850	25 - 30	1,400 - 1,800	170 - 710	No	Yes	B,I	Nat. Gas	15 - 45 psig	1,200 - 2,400
Phosphoric Acid	Demo/Comm	1998	200	0	3,500 - 3,750	140 - 250	No	Yes	B,I	Nat. Gas, Propane	.15 - .5 psi	180
Proton Exchange Membrane	Dev/Demo	1998 - 2000	3 - 250	0 - 33	2,000 - 3,250	135 - 165	No	Yes	B,I,P	Nat.Gas, Propane, Butane, Diesel	gas pipeline press.	60
Hybrid Solid Oxide	Dev/Demo	2001 - 2003	225 - 2,240	25	540 - 1,100	350 - 420	No	Yes	B,I	Nat. Gas	None Reported	2 (see note)
Solar Electric												
Photovoltaics	Dev/Demo/Comm		10 - 10,000	0	0	0	No	No	P	Solar		0
Dish Stirling	Dev/Demo	1999	5 - 25	0 - 10	6,800	150	No	Yes (when fossil fueled)	B,I,P	Solar, Fossil Fuels	>300 W/m2	3 - 5
Wind Turbines												
<50 kW	Comm		0.85 - 50	1	0	0	No	No	P (w/ storage)	Wind	>8 MPH Wind	.08 - .16
>50 kW	Comm		50 - 1,000	1	0	0	No	No	I	Wind	>10 MPH Wind	0.16 - 0.5
STORAGE												
Batteries	Dev/Demo/Comm	1997 - 2000	100 - 20,000					Yes	B,I,P	Electricity	N/A	0 - .004
Flywheels	Dev/Demo/Comm	1997 - 2000	10 - 3,000	0 - 10	0	0	No	Yes	P	Electricity	N/A	0 - 40

Table 6 – DER Technology Matrix cont.

	MAINTENANCE		SITING & ENVIRONMENTAL								
	Time Before Intervention (opr hrs)	Time Between Overhauls (opr hrs)	Power Plant Size		Infrastructure Needs						Air Emission Controls
			Footprint (sqft/kW)	Volume (cuft/kW)	Weight (lb/kW)	Water Service	Waste Water Service	Fuel Delivery	Maint. Access	Telecom-munications	
GENERATION											
Reciprocating I/Cs											
Diesel	1,500 - 2,000	25,000 - 30,000	.22			Engine Coolant	No	Yes	Yes	Optional	None Reported
Otto (Spark Ignition)	280 - 1,000	24,000 - 60,000	.22 - .31	3 - 6	22 - 65	Engine Coolant	No	Yes	Yes	Optional	None Reported, SCR
Gas Turbines											
Micro-Turbines	750 - 10,000	5,000 - 40,000	0.15 - 1.5	0.6 - 4.0	2.6 - 37	None Reported	None Reported	Yes	Yes	Optional	None Reported, Catalytic
Small Gas Turbines	4,000 - 8,000	30,000 - 50,000	.02 - .61	.30 -1.06	7 - 26	None Reported	None Reported	Yes	Yes	Optional	None Reported, Water/Steam Injection, SCR, OLN Com b.
Fuel Cells											
Molten Carbonate	720	40,000	1 - 4	8 - 40	120 - 240	Yes or Can Be Self Sufficient	Yes or No	Yes	Yes	Optional	None Reported
Phosphoric Acid	2,200 - 8,760	40,000	4	40	200	None Reported	None Reported	Yes	Yes	Yes	None Reported
Proton Exchange Membrane	8,700	8,700 - 40,000	0.6 - 3	4.7 - 9	100 - 300	Possible	None Reported	Yes	Yes	Optional	None Reported
Hybrid Solid Oxide	8,000	40,000	1.1 - 1.2	18 - 20		None Reported	None Reported	Yes	Yes	Optional	None Reported
Solar Electric											
Photovoltaics			538			None	None	No	Yes	Optional	None
Dish Stirling	8,000	30,000	160 - 269		600	None	None	No	Yes	No	Low NOx Burner
Wind Turbines											
<50 kW	30,000	200,000	1.5 - 9.0	9 - 24	330 - 720	None	None	No	Yes	No	N/A
>50 kW	4,000	130,000	0.24 - 110		250	None	None	No	Yes	Optional	N/A
STORAGE											
Batteries	8,700		1 - 7		124 - 186	None	None	Yes (Electricity)	Yes	Optional	N/A
Flywheels	8,700 - 18,000	10,000 - 175,000	.013 - .830	0.5 - 6.0	1.3 - 17	None	None	Yes (Electricity)	Yes	Optional	N/A

Table 6 – DER Technology Matrix cont.

	SITING & ENVIRONMENTAL										PERFORMANCE					
	Air Emissions (lb/kWh, unless indicated otherwise)					Noise (dB @ ? ft)	Water Consumption (Gal./kWh)	Waste Water Production (Gal./kWh)	Hazardous Materials	Other Hazards	Net Electric Heat Rate (HHV Btu/kWh)			Expected Availability (%)	Typical Forced Outage Rate (%)	Load Ramp Rate (kW/min)
	CO	NOx	SOx	UHC	PM10						Full Load (100% FL)	Reduced Load (75% FL)	Mid-Load (50% FL)			
GENERATION																
Reciprocating I/Cs																
Diesel		.022 - .025				60 - 85 dB @ 23 ft	Nearly Zero Reported	Zero Reported	None Reported	None Reported	7,900 - 9,500		9,158 - 10,989	90	1	
Otto (Spark Ignition)	0.004 - 0.006	0.0015 - 0.037	0.0	0.0009	0.0002	100 @ 3.3 ft	Nearly Zero Reported	Zero Reported	None Reported	None Reported	9,300 - 11,800	9,600 - 11,000	10,200 - 11,400	97 – 98	1	250 - 1,000
Gas Turbines																
Micro-Turbines	3 - 50 ppm	3 - 50 ppm	Negligible	3 - 9 ppm	Negl.	<60 dB @ 33 ft or <60 dB @ 10 ft	Zero Reported	Zero Reported	None Reported	Batteries	10,300 - 16,484	11,300 - 17,000	12,200 - 25,043	92 - 98+	1 - 5	25 - 250
Small Gas Turbines	<15 - 50 ppm	.007 - .009 <9 ppm	Negligible	<15 - 25 ppm	Negl.	60 – 85 @ 23 ft or 85 dB @ 3 ft	Zero Reported	Zero Reported	None Reported	None Reported	8,400 - 16,000	9,000 - 11,000	9,850 - 12,200	90 – 98	1 - 3	
Fuel Cells																
Molten Carbonate	0.00001	<0.000002	<0.000003	Negligible	Negligible	60 dB @ 30 ft or 60 dB @ 100 ft	0 - 0.125	0 - 0.044	None Reported	None Reported	6,545 - 7,580	6,270 - 8,040	6,100 - 9,090	>95	<5%	7 - 285
Phosphoric Acid	0.000023	0.000016	0	0.0000004	0	62 dB @ 30 ft	Zero Reported	Zero Reported	None Reported	None Reported	9,450	9,450	9,450	97.7	1.2	80 kW Instantaneous
Proton Exchange Membrane	Negl.	Negl.	0	0	0	50 dB @ 6 ft 65 dB @10 ft	0 - 0.2	Zero Reported	Batteries	None Reported	9,492 - 9,763	9,235 - 9,492	8,543 - 9,492	>95	<1	0.5
Hybrid Solid Oxide	0.0	0.00005 - 0.00006	0	0	0	60 dB @ 30 ft	Zero Reported	Zero Reported	Spent Desulfurizer Reagent	None Reported	5,380 - 6,120	6,110 - 6,640	6,240 - 6,670	94	4	
Solar Electric																
Photovoltaics	0	0	0	0	0	0	0	0	None	None Reported	22,780 solar to electric					
Dish Stirling	.02	.02				Negligible	0	0	Hydrogen	None Reported	8,400 - 16,600	11,000 - 18,500	16,700 - 21,500	95		
Wind Turbines																
<50 kW	N/A	N/A	N/A	N/A	N/A	58 - 64 @ 100 ft	0	0	Batteries	None Reported	N/A	N/A	N/A	95 - 99	0 - 1	N/A
>50 kW	N/A	N/A	N/A	N/A	N/A	45 dB @ 820 ft	0	0	Hydraulic Fluid	Aviary Hazard	N/A	N/A	N/A			N/A
STORAGE																
Batteries							0	0	Low Risk VRLA Batteries	None	N/A	N/A	N/A	100%	0 - 0.55%	Nearly Instantaneous
Flywheels						0 - 68 dB @ 3 ft	0	0	None	high energy rotor	N/A	N/A	N/A	>95%	0	Nearly Instantaneous

Table 6 – DER Technology Matrix cont.

	ECONOMICS						POWER QUALITY			ENERGY STORAGE			
	Installed Capital Cost ($/kW)	Installation Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable Non-Fuel O&M ($/kWh)	Power Plant Life (yrs)	Construction Lead Time (months)	Voltage THD (%)	Current THD (%)	Full Load Power Factor	Stored Energy Capacity (kWh)	Discharge/Charge Efficiency (%)	Stand-By Losses (% cap/hr)	Time-to-Charge (hrs)
GENERATION													
Reciprocating I/Cs													
Diesel	200 - 250	50 - 100		.005	30	3 - 12				N/A	N/A	N/A	N/A
Otto (Spark Ignition)	200 - 800	50 - 100	1.6 - 11.4	0.007 - 0.011	25 -35	8 - 9	5	5	0.8 - 1.0	N/A	N/A	N/A	N/A
Gas Turbines													
Micro-Turbines	250 - 1,250	35 -150		0.002 - .010	5 - 20+	0 - 1	<5%	<5%	0.8 - 1.0	N/A	N/A	N/A	N/A
Small Gas Turbines	300 - 870	50 - 120		.002 - .008	20 - 50	3 - 16				N/A	N/A	N/A	N/A
Fuel Cells													
Molten Carbonate	815 - 1,900	100 - 435	70	.003	30 - 35	12 - 24	<3%	<3%	0.85 - 1.0 lead or lag	N/A	N/A	N/A	N/A
Phosphoric Acid	3000	450 -750		.008 - .010	20	7	<3% balanced linear load		.85 lead or lag	N/A	N/A	N/A	N/A
Proton Exchange Membrane	4,000	1,000		0.010 - 0.045	15 -25	1	<5%	<5%	.8 lead or lag	4	40		4
Hybrid Solid Oxide	1,150 - 1,300	180 - 230	25 - 50	.002 - .003	30	3 - 6	Per IEEE Specs.	Per IEEE Specs.	1.0	N/A	N/A	N/A	N/A
Solar Electric													
Photovoltaics	5,000 - 10,000			.001 - .004						N/A	N/A	N/A	N/A
Dish Stirling	3,800 - 4,000			.05 - .025		1	0.5	0.5		N/A	N/A	N/A	N/A
Wind Turbines													
<50 kW	2,600 - 4,600	1,000 - 4,000			30	2	0.03	0.05	0.98				
>50 kW	850 - 1,500	60 - 175	4.2 - 70	.003 - .021	20 - 25	8 - 12			leading or lagging controller	N/A	N/A	N/A	N/A
STORAGE													
Batteries	620 - 1,250	200 - 416	10 - 42	.0076	30	9 - 12	<5	<5	variable	1,600 - 4,300	74 - 85	0 - 1	6 - 8
Flywheels	150 - 900	30 - 480	4 - 5		10 - 30	1 - 12	<5	<5	.90 - .98	1 - 2,000	82 - 90	<1	0.1 - 1.3

Appendix A: Sample Specification Sheets for Caterpillar DG Controls[9]

[9] Refer to Caterpillar website for updated materials: http://www2.cat.com/cgi-bin/frameset.pl?nav=products&content=/products/

Appendix B: Sample Specification Sheets for ENCORP DG Control Software & Hardware[10]

[10] Refer to ENCORP website for updated materials: http:/www.encorp.com/support/body_support.html