Itron

Knowledge to Shape Your Future

Electric | Gas | Water

information collection, analysis and application

# CPUC Self-Generation Incentive Program

# Optimizing Dispatch and Location of Distributed Generation

Submitted to:

**PG&E**
**and**
**The Self-Generation Incentive Program Working Group**

Prepared by:

Itron, Inc.
601 Officers Row
Vancouver, Washington  98661

and

BEW Engineering
2302 Camino Ramon, Suite 220
San Ramon, California  94583

July 2010

# *ACKNOWLEDGEMENTS*

We would like to acknowledge the following for their contributions to the DG Study:

- Molly Sterkel and Neal Reardon at the California Public Utilities Commission, who provided overall direction for the study;
- Betsy Wilkins for her comments and feedback on earlier drafts, and patience;
- Matt Heling and other staff at PG&E for providing demand data and insightful comments on utility distribution needs and operations;
- Dan Hopper, Pierre Landry, and the distribution system staff at SCE for providing demand data and feedback on earlier drafts and the presentations;
- Steven Jaffe, Dean Kinports, and distribution system staff at SDG&E for providing information and insights on their distribution networks;
- Ron Davis, Emma Stewart, and Billy Quach of BEW Engineering for their enthusiasm, innovativeness, and professionalism; and
- Collin Elliot, Stephan Barsun, Kurt Scheuermann, and Myles O'Kelly at Itron for innovative approaches to developing representative data classifications; and Brenda Latter for her willingness to edit and format the report under always challenging circumstances.

# Glossary

**Aggregated Megawatt Contingency Overload (AMWCO):** A PowerWorld-defined item that aggregates the percentage of overloads over 100 percent multiplied by the line rating of the distribution or transmission line.

**Bus:** An element defined in a power flow model that is used to interconnect multiple circuits or feeders to a common point in the substation. *(See also: Swing Bus)*

**Capacitor Banks:** Reactive power equipment installed on a distribution circuit to correct the circuit power factor to close to unity which increases the voltage of the circuit.

**Distributed Generation Transmission Benefit Ratio (DGTBR):** An integer value that is assigned to quantify the level of benefit for distributed generation.

**Feeder:** A distribution feeder circuit is an electrical power line with a voltage level of 12 kV or less that delivers power from the distribution substation to the end users, e.g., residential, commercial, or industrial customers.

**Line Losses:** Electrical energy loss on a distribution circuit due to heat, resistance, and other electrical components or devices. The difference between power required by the end user and power supplied from the substation or generator.

**Load Following:** A power plant that is capable of adjusting its power output as demand for electricity fluctuates throughout the day.

**One-Line Diagram:** The conversion of a multiple-phased power line to one single one-line representation with other electrical components denoted to simpler symbols.

**Radial Taps:** An interconnection point on the distribution feeder that connects a remote generator or customer load to the main distribution circuit.

**Spinning Reserves:** The on-line reserve capacity that is ready to meet electric demand within a set amount of time of a dispatch by an electrical system operator.

**Swing Bus:** A swing bus can also be referred to as a slack bus. It is an element that must be defined in a power flow model as an infinite generating power source or substation providing power. The swing bus is often paired with a generator used to compute the power flow solution.

**Transmission Loading Relief (TLR) Sensitivities:** A PowerWorld tool to determine the sensitivity of the flow on a single monitored element, such as a transmission line, to many different transactions in the system.

**Utility Call for Power:** A request from the utility to facilities with generation reserves to support additional services of generating capacity, energy supply, and power delivery to the electrical grid.

# Table of Contents

**1 Executive Summary ........................................................................ 1-1**

1.1 Introduction and Background ........................................................ 1-1
*Background ........................................................................................ 1-1*
*Report Scope ...................................................................................... 1-2*
*Study Objectives ................................................................................. 1-3*
*Report Organization ........................................................................... 1-3*
1.2 Key Findings ...................................................................................... 1-4
*DG System Dispatch ........................................................................... 1-4*
*Locational Aspects of DG Systems in California's Electricity System ............ 1-10*

**2 Background and Approach ................................................................ 2-1**

2.1 DG Resources in California's Electricity System .............................. 2-1
*Development, Status, and Prospects of DG in California ........................ 2-1*
*The Role of DG Dispatch in Meeting Energy Needs .................................. 2-2*
*Strategic Aspects of DG Location in the Grid ........................................... 2-2*
*DG Systems Deployed in the SGIP ........................................................... 2-3*
2.2 Analytical Approach ........................................................................... 2-9
*Approach to Assessing DG Dispatch ......................................................... 2-9*
*Approach to Assessing Locational Aspects of DG ..................................... 2-25*

**3 Study Results ...................................................................................... 3-1**

3.1 Representative DG Generation Profiles .............................................. 3-1
*Observations on Representative DG Generation Profiles ......................... 3-11*
3.2 Representative SGIP Facility Demand Profiles .................................. 3-11
*Mean Demand Profiles ............................................................................ 3-12*
*Generation with Total Site Demand ......................................................... 3-15*
*Observations on Representative Site Demand Profiles ............................. 3-21*
3.3 Improving Dispatch of DG Resources ................................................ 3-22
*Modeling and Analysis of a PG&E Feeder ................................................. 3-22*
*Modeling and Analysis of an SCE Feeder .................................................. 3-34*
*Modeling and Analysis of an SDG&E Feeder .............................................. 3-44*
*Other Utility Feeders Included in the Study ................................................ 3-53*
*Aggregated Results:  All Distribution Feeders and Generators ................... 3-54*
3.4 Optimizing Locations of DG Resources .............................................. 3-57
*2020 Summer Status—Base Case ............................................................. 3-57*
3.5 Conclusions and Recommendations ................................................... 3-63
*Demand Response Requirements ............................................................. 3-63*
*Call for Power and Generator Optimization ................................................ 3-65*

**4 Data Sources ....................................................................................... 4-1**

4.1 Selection of Representative Distribution Feeders ............................... 4-3
*Development of Distribution Power Flow Data Sets .................................... 4-4*
*Treatment of Aggregated Feeders .............................................................. 4-6*
*Transmission Loading Data Set ................................................................. 4-7*

***Appendix A*** **Analyses of Additional Distribution Feeders Examined for the Study ........ A-1**

A.1 Summary of Other PG&E Feeders ........ A-1
*PG&E C ........ A-1*
*PG&E A ........ A-8*
A.2 Summary of other SCE Feeders........ A-16
*SCE D........ A-16*
*SCE B........ A-22*
A.3 Summary of Other SDG&E Feeders........ A-27

***Appendix B*** **Methodology and Results for Establishing Representative Generation Profiles and Site Demand Profiles ........ B-1**

B.1 Introduction........ B-1
B.2 Development of Generation Profiles........ B-3
B.3 Demand Profiles for Sites with Demand Data ........ B-19
*Site-Level Demand Profiles........ B-19*
*Mean Demand Profiles........ B-25*
B.4 Analysis of Generation with Total Site Demand ........ B-26
B.5 Contribution of Generation to Site Demand........ B-34

## List of Tables

Table 1-1:  Average MW Losses for Each Type of Operation ........1-9
Table 1-2:  Top Bus Locations for Installing DG Systems ........1-12
Table 1-3:  Relationships Between Blended DG Mixes and Analyzed Distribution Feeders........1-13
Table 2-1:  Summary of Data Provided for Study........2-10
Table 2-2:  Examined Distribution Feeders and Feeder Characteristics ........2-20
Table 2-3:  Time, Magnitude, and Date of Peak Load for Selected Feeders........2-22
Table 3-1:  Counts of Final Load Profiles Classified by Technology ........3-6
Table 3-2:  Mean Percent of Days Classified by Technology........3-7
Table 3-3:  Count of Sites with Demand Data ........3-12
Table 3-4:  Overall Energy Output Calculations ........3-32
Table 3-5:  Average MW Losses for Each Type of Operation ........3-33
Table 3-6:  Energy Available and Energy Output over 24 Hours for SCE C........3-43
Table 3-7:  Average Losses and Percentage Change in Losses from No DG Option to DG Added Option for SCE C ........3-44
Table 3-8:  SDG&E B Energy Output Calculations........3-51
Table 3-9:  SDG&E B Average MW Losses ........3-52
Table 3-10:  Relationships Between Original DG Systems on Analyzed Feeders........3-54
Table 3-11:  Relationships Between Blended DG Mixes and Analyzed Distribution Feeders ........3-56
Table 3-12:  Installed DG Capacity per County for Top 200 Optimal Locations ....3-62
Table 3-13:  Loss Reduction on Feeders by Dispersing Generation........3-68
Table 4-1:  Summary of Data Provided for Study........4-2

Table 4-2: Examined Distribution Feeders and Feeder Characteristics ................4-4
Table A-1: Energy from Different Generation Configurations over 24 Hours......... A-6
Table A-2: Average Losses over 24 Hours of Peak Day ...................................... A-7
Table A-3: Energy Output in Different Generation Scenarios for PG&E A .......... A-15
Table A-4: Average MW Loss for PG&E A over 24 Hours.................................. A-15
Table A-5: Energy Provided by Generators and Swing Bus For SCE D............. A-20
Table A-6: Average Losses over 24 Hour Simulation for SCE D......................... A-21
Table A-7: Energy Provided by Generators and Swing Bus for SCE B............... A-26
Table A-8: Average Losses over 24 hour Simulation for SCE B ......................... A-26
Table B-1: NAICS Code Mapped to Occupancy and Process Site Types............. B-2
Table B-2: Initial Count of Sites with Generation Data ......................................... B-3
Table B-3: Counts of Sites Classified as Baseload Generation Profiles by Size of Deviation and Percent Occurrence by Technology Type ................................ B-8
Table B-4: Counts of Final Load Profiles Classified by Technology ...................... B-9
Table B-5: Mean Percent of Days Classified by Technology............................... B-10
Table B-6: Count of Sites with Demand Data..................................................... B-19
Table B-7: Mean Correlations of Generation and Site Demand .......................... B-33

## List of Figures

Figure 1-1: Example of Generator Output Against Demand..................................1-6
Figure 1-2: Dispatch of Swing Bus and DG Resources to Meet Feeder Peak Demand..........................................................................................................1-7
Figure 1-3: Demand Response Required for Microturbine Combined with PV.......1-8
Figure 1-4: Available Power from the DG Generator Combined with PV ...............1-9
Figure 1-6: Summary Results for Optimizing DG Location for Transmission .......1-11
Figure 2-1: Typical DG Electricity Generation Profiles ..........................................2-4
Figure 2-2: Characteristic Electrical Load Profile ..................................................2-6
Figure 2-3: Load Profile Where PV has Minimal Effect on Peak Load ...................2-8
Figure 2-4: Overview of Analytical Approach ......................................................2-11
Figure 2-5: Condensed Hourly Generation Profile for a Fuel Cell ........................2-12
Figure 2-6: Example of Baseload Generation Profile ...........................................2-13
Figure 2-7: Example of Non-Baseload Generation Profile....................................2-14
Figure 2-8: Example of Generation Profiles Used to Determine MT Capabilities..........................................................................................................2-14
Figure 2-9: Example of Maximum Ramping of ICE ..............................................2-15
Figure 2-10: Example of Maximum Ramping of MT ............................................2-16
Figure 2-11: Non-Baseload Generation Profile for Occupancy-Oriented Facility...............................................................................................................2-17
Figure 2-12: Non-Baseload Generation Profile for Process-Oriented Facility ......2-18
Figure 2-13: California Building Climate Zones ...................................................2-19
Figure 2-14: Selection of Peak Day Generation Data...........................................2-21
Figure 2-15: Sanitized Sample Feeder Circuit......................................................2-23
Figure 2-16: Example of Aggregated Transformer ..............................................2-24
Figure 2-17: Example of Swing Bus Modeling......................................................2-25

Figure 3-1: Example of a Volatile Generation Day—ENGO as Percent of Average ENGO ....... 3-2
Figure 3-2: Example of a Non-Volatile Load Day—ENGO as Percent of Average ENGO ....... 3-3
Figure 3-3: Example of a Volatile Load, All June Days—ENGO as Percent of Average ENGO ....... 3-4
Figure 3-4: Example of a Non-Volatile Load, All June Days—ENGO as Percent of Average ENGO ....... 3-5
Figure 3-5: Average Capacity Factors for Baseload and Non-Baseload, Coastal ....... 3-9
Figure 3-6: Average Capacity Factors for Baseload and Non-Baseload, Inland ....... 3-9
Figure 3-7: Average Capacity Factors for Baseload and Non-Baseload, Process Sites ....... 3-10
Figure 3-8: Average Capacity Factors for Baseload and Non-Baseload, Occupancy Sites ....... 3-10
Figure 3-9: Plot of Metered Demand, All Days with Mean ....... 3-13
Figure 3-10: Plot of Total Demand, All Days with Mean ....... 3-13
Figure 3-11: Mean Demand Profiles for Coastal and Inland Locations ....... 3-14
Figure 3-12: Mean Demand Profiles for Occupancy- and Process-Based Sites ....... 3-15
Figure 3-13: Scatter of Generation and Demand by Maximum Demand Day Quartiles, Low Correlation ....... 3-16
Figure 3-14: Average Hourly Generation and Total Demand, Low Correlation ....... 3-17
Figure 3-15: Scatter of Generation and Demand by Maximum Demand Day Quartiles, High Correlation (Case One) ....... 3-18
Figure 3-16: Average Hourly Generation and Total Demand, High Correlation, (Case One) ....... 3-19
Figure 3-17: Scatter of Generation and Demand by Maximum Demand Day Quartiles, High Correlation (Case Two) ....... 3-20
Figure 3-18: Average Hourly Generation and Total Demand, High Correlation (Case Two) ....... 3-21
Figure 3-19: Original One-Line Diagram of PG&E B ....... 3-23
Figure 3-20: Equivalent One-Line Diagram of PG&E B ....... 3-23
Figure 3-21: Demand Profile for Feeder PG&E B ....... 3-24
Figure 3-22: Generation Profile for SGIP Generator on PG&E B (250 kW MT) ....... 3-25
Figure 3-23: Per Unit Representation of Generator Output Against Demand ....... 3-25
Figure 3-24: DG Generation during top 200 Hours of PG&E B Feeder Demand ....... 3-26
Figure 3-25: Demand Profile and the Contribution of Each Generator to the Profile ....... 3-28
Figure 3-26: Output Power from the SGIP Generator with the Excess Power Available while Load Following ....... 3-29
Figure 3-27: Ramping Required from the 4.5 MW MT Load Following System ....... 3-29
Figure 3-28: New Demand Profile with High PV Penetration Dispersed Across the Loaded Buses ....... 3-30
Figure 3-29: Demand Response Required for Microturbine Combined with PV ....... 3-31
Figure 3-30: Available Power from the DG Generator Combined with PV ....... 3-31
Figure 3-31: MW Losses over 24 Hours in Different Configurations of Generation3-33

Figure 3-32: One-Line Diagram for SCE C....3-34
Figure 3-33: Equivalent One-Line Diagram for SCE C....3-35
Figure 3-34: Demand Profile for Peak Day (July 10, 2008) on SCE C....3-36
Figure 3-35: Demand and Generator Data in per Unit Form for SCE C....3-36
Figure 3-36: DG Output in 2008 during Top 200 Hours of Demand on SCE C....3-37
Figure 3-37: SCE C Demand Profile for the Peak Demand Day (July 10, 2008)....3-38
Figure 3-38: Ramping Required from 3.8 MW SGIP ICE Unit when Operated in a Load Following Configuration on SCE C....3-39
Figure 3-39: Excess Power Available from the 3.8 MW ICE System on SCE C...3-39
Figure 3-40: Stacked Generation Plot of the SCE C Feeder with ICE and 15% Dispersed PV....3-40
Figure 3-41: Ramp Rate Requirements for the ICE Unit when Paired with PV on SCE C....3-41
Figure 3-42: Available Power Plot from ICE and PV on SCE C....3-42
Figure 3-43: Losses over the 24-Hour Period on SCE C with Different Configurations....3-43
Figure 3-44: Power World One-Line of SDG&E B....3-45
Figure 3-45: SDG&E B Feeder Demand Profiles....3-45
Figure 3-46: 152 kW SGIP PV Generation Profile....3-46
Figure 3-47: Per Unit Representation of PV and Feeder Demand for SGD&E B....3-47
Figure 3-48: DG Output During Top 200 Hours of Feeder Demand on SDG&E B....3-48
Figure 3-49: SDG&E B PV Scaled to 1.3 MW....3-49
Figure 3-50: New Generation Profile with Fixed Swing Generation, Scaled PV, and MT Unit....3-49
Figure 3-51: 5 MW Microturbine Generation and Excess Capacity....3-50
Figure 3-52: Required Ramp Rate for 5 MW MT on SDG&E B....3-51
Figure 3-53: SDG&E B Feeder Losses....3-53
Figure 3-54: 2020 Summer Base Case WTLR Map....3-58
Figure 3-55: 2020 Summer Base Case with 500 MW of DG....3-59
Figure 3-56: 2020 Summer Base Case with 1,000 MW of DG....3-60
Figure 3-57: WTLR Comparison Between Base Case and Different DG Penetrations....3-61
Figure 3-58: SDG&E Demand Response Rate Distribution....3-63
Figure 3-59: PG&E Demand Response Rate Distribution....3-64
Figure 3-60: Call for Power for an Off-Peak Generator Plus Available Power from the Generator....3-65
Figure 3-61: Losses are Minimized on the Feeder when Operating as a Non-Demand Following Generator....3-66
Figure 3-62: New Generation Blend for PG&E B....3-67
Figure 4-1: California Building Climate Zones....4-3
Figure 4-2: Sample Feeder Circuit....4-5
Figure 4-3: Example of Aggregated Transformer....4-6

Figure 4-4: Example of Swing Bus Modeling....................4-7
Figure A-1: Load Profile for Feeder PG&E C .................... A-1
Figure A-2: ICE Original DG Load Profile.................... A-2
Figure A-3: DG Capacity Factor for Top 200 Hours of Demand on PG&E C ........ A-3
Figure A-4: Plot of PG&E C, Combined with 15% (1.3 MW), PV, and a 3.2 MW ICE .................... A-4
Figure A-5: Excess Power Available .................... A-5
Figure A-6: Ramp Rate Required from ICE with PV.................... A-5
A-7: Ramp Rate Required from ICE without PV.................... A-6
Figure A-8: MW Losses over the 24-Hour Period with Different Generation Configurations.................... A-7
Figure A-9: Load Profile for Peak Day (July 8, 2008) .................... A-8
Figure A-10: Per Unit Load Profile and MT Generation Profile* .................... A-9
Figure A-11: DG Capacity Factor During Top 200 Hours of Feeder Demand on PG&E A.................... A-10
Figure A-12: Additional 3 MW ICE Unit Added To PG&E A's Generation Profile A-11
Figure A-13: Rate Required For 3 MW ICE Only .................... A-12
Figure A-14: Rate Required For Full Load Change Rate .................... A-12
Figure A-15: Available Power From ICE Unit .................... A-13
Figure A-16: PV Combined with Two ICE Units, 3 & 3.2 MW (15% of Peak Load for the PV, 1.2 MW).................... A-13
Figure A-17: Required ICE Ramp Rates .................... A-14
Figure A-18: Available Power for PV & ICE.................... A-14
Figure A-19: Losses Over 24-Hour Period With Different Generation Configurations.................... A-15
Figure A-20: SCE D Feeder Demand and 15% PV Profile.................... A-16
Figure A-21: DG Capacity Factor During the Top 200 Hours of Feeder Demand.................... A-17
Figure A-22: Required Ramp Rate for Load Following Units on SCE D............. A-18
Figure A-23: New DG Profiles with Load Following Capability for SCE D........... A-19
Figure A-24: Ramp Rate Required for New DG units on SCE D.................... A-20
Figure A-25: Average Feeder Losses for SCE D .................... A-21
Figure A-26: SCE B Feeder Demand and 60 kW MT Profile.................... A-22
Figure A-27: DG Capacity Factor During top 200 Hours of Feeder Demand ...... A-23
Figure A-28: SCE B DG MT Profile and Load Following Requirement............... A-24
Figure A-29: Required Ramp Rate for Load Following Units on SCE B.............. A-25
Figure A-30: Required Ramp Rate for New DG Units on SCE B .................... A-25
Figure A-31: Average Feeder Losses for SCE B.................... A-27
Figure B-1: Example of a Volatile Load Day—Generation as Percent of Daily Mean .................... B-4
Figure B-2: Example of a Non-Volatile Load Day—Generation as Percent of Daily Mean .................... B-5
Figure B-3: Example of a Volatile Load, All June Days—Generation as Percent of Daily Mean .................... B-6
Figure B-4: Example of a Non-Volatile Load, All June Days—Generation as Percent of Daily Mean.................... B-7

Figure B-5: Mean Generation Capacity Factors for Baseload and Non-Baseload, Coastal ... B-11
Figure B-6: Mean Generation Capacity Factors for Baseload and Non-Baseload, Inland ... B-12
Figure B-7: Mean Generation Capacity Factors for Baseload and Non-Baseload, Process Sites ... B-13
Figure B-8: Mean Generation Capacity Factors for Baseload and Non-Baseload, Occupancy Sites ... B-14
Figure B-9: Typical Baseload Generation Profile, Partial Day Operation ... B-15
Figure B-10: Typical Baseload Generation Profile, 24-Hour Operation ... B-16
Figure B-11: Typical Non-Baseload Generation Profile, Single Peak ... B-17
Figure B-12: Typical Non-Baseload Generation Profile, Multiple Peak ... B-18
Figure B-13: Mean Demand as Percent of Maximum Demand by Site, Inland Locations ... B-20
Figure B-14: Mean Demand as Percent of Maximum Demand by Site, Coastal Locations, Group One ... B-21
Figure B-15: Mean Demand as Percent of Maximum Demand by Site, Coastal Locations, Group Two ... B-22
Figure B-16: Plot of Metered Demand, All Days with Mean ... B-23
Figure B-17: Plot of Total Demand, All Days with Mean ... B-24
Figure B-18: Mean Demand Profiles for Coastal and Inland Locations ... B-25
Figure B-19: Mean Demand Profiles for Occupancy- and Process-Based Sites. B-26
Figure B-20: Scatter of Generation and Demand by Maximum Demand Day Quartiles, Low Correlation ... B-27
Figure B-21: Mean Hourly Generation and Total Demand, Low Correlation ... B-28
Figure B-22: Scatter of Generation and Demand by Maximum Demand Day Quartiles, High Correlation Case One ... B-29
Figure B-23: Mean Hourly Generation and Total Demand, High Correlation, Case One ... B-30
Figure B-24: Scatter of Generation and Demand by Maximum Demand Day Quartiles, High Correlation Case Two ... B-31
Figure B-25: Mean Hourly Generation and Total Demand, High Correlation Case Two ... B-32
Figure B-26: Generation as Share of Demand by Demand Deciles and Generation Profile ... B-34
Figure B-27: Generation as Share of Demand by Demand Deciles and Technology Type ... B-35
Figure B-28: Generation as Share of Demand by Demand Deciles and Site TypeB-36
Figure B-29: Generation as Share of Demand by Demand Deciles and Location ... B-37

# 1

# Executive Summary

## 1.1 Introduction and Background

### *Background*

Distributed generation (DG) technologies emerged from energy policies in the 1970s[1] that targeted the development of non-utility generation that would be more efficient, responsive, and diverse than utility generation technologies. California has seen significant growth in DG technologies as a result of special incentive and procurement programs targeting DG development. These programs have resulted in a total DG capacity in California ranging in the 1000s of MW.[2] However, there have been questions about the level of success of DG facilities in achieving the goals of being more efficient and responsive than utility generation.

As a result of the mixed success of DG technologies, there has also been some controversy as to their value to utilities and ratepayers. On one hand, DG systems that provide power when needed, can potentially act as a powerful source of reserve power for the utility. In addition, due to the dispersed nature of DG technologies, they inherently provide the capability of supplying power in areas most needing congestion relief. Currently, the utilities do not have the authority, training, or infrastructure to control large numbers of dispersed DG resources. Moreover, many utility engineers and planners believe that DG technologies have not demonstrated the ability to provide power when needed. Similarly, there has been little attempt at locating DG facilities strategically to help reduce congestion on transmission and distribution circuits. As a result, there has been little evidence that the location of DG facilities helps to reduce congestion or peak loading on transmission and distribution lines.

In 2006, an Itron team (composed of Itron; Energy and Environmental Economics; and Davis Power Consulting[3]) investigated the impacts of DG systems deployed under the SGIP on the transmission and distribution systems of California's electricity system. Results of the analysis were contained in the 2007 report "CPUC Self-Generation Incentive Program Sixth Year Impact

---

[1] Key legislation laying the policy foundation for DG technologies included the Public Utility Regulatory Policy Act (PURPA) of 1978.

[2] Itron, Inc., *Impacts of Distributed Generation*, for the California Public Utilities Commission, January 2010.

[3] Now part of BEW Engineering.

Evaluation."[4] In general, those results indicated that DG systems could possibly provide reliability and congestion relief to California's T&D system. However, the team also pointed out that the results were based on limited data and restricted time periods; and there was high uncertainty in translating the results to the overall T&D system.

Since 2006, a number of questions have emerged about the benefits of DG systems to California's electricity system, including:

- What is the impact of DG systems on meeting peak demand of the customer as well as the utility and to what extent does this peak demand overlap?
- If the peak demand of the utility customer and the utility do not overlap, to what extent can DG technologies respond to either or both of these demands?
- Can DG systems be strategically located to provide congestion relief or improvements in reliability to California's electricity system?

The CPUC directed Itron to conduct a study on DG dispatch and strategic location within California's electricity system to address these questions. This "DG Study" is the result of the Itron team's[5] investigations.

### Report Scope

The purpose of the DG Study is to assess the feasibility of improving the dispatch and strategic location of DG resources in California's electricity system. We felt it was important to use actual performance data where possible in assessing dispatch and strategic location of DG resources. As a result, we relied heavily on metered data from California's Self-Generation Incentive Program (SGIP). The SGIP is one of the largest and most diverse DG incentive programs in the country. As of the end of calendar year 2008, there were over 1,270 DG systems deployed under the SGIP representing over 337 megawatts (MW) of rebated capacity.[6] DG technologies deployed under the SGIP have included solar photovoltaic (PV) systems, wind turbines, and natural gas, as well as biogas-powered fuel cells, microturbines, internal combustion (IC) engines, and small gas turbines.[7] Due to the size and diversity of the SGIP, the scope of this report is focused on DG technologies operating under the SGIP in 2008. Calendar year 2008 was selected for the study timeframe due to the completeness of data sets on

---

[4] Itron, *CPUC Self-Generation Incentive Program: Sixth-Year Impact Evaluation Final Report*, August 30, 2007.

[5] In this report, references to the Itron team or team means the team of Itron and BEW Engineering.

[6] Itron, *CPUC Self-Generation Incentive Program: Eighth-Year Impact Evaluation Final Report*, June 2009.

[7] Although wind energy systems are eligible under the SGIP, there were very few wind energy systems operating in the SGIP in calendar year 2008, and there was no metered generation data available for these systems. As such, wind energy systems were excluded from the scope of this study.

generation and demand for this time period. Metered generation data included 15-minute interval data obtained from SGIP facilities during 2008 with a strong focus on the four summer months of June, July, August, and September of 2008. Complementary demand data were obtained for selected distribution feeders and facilities housing SGIP systems.

### *Study Objectives*

The DG Study has two overall goals tied to answering outstanding questions about the role of DG technologies in California's electricity system:

1. Examine the current dispatchability of DG systems operating under the SGIP and examine the impact of the locations of these DG facilities on the associated transmission and distribution systems
2. Investigate the ability to improve the dispatchability and location of DG technologies so as to increase the benefits to DG system owners, the utilities, ratepayers, and society at large.

### *Report Organization*

This report is organized into four sections and two appendices:

- **Section 1** is this executive summary, which summarizes the overall purpose of the DG Study, its scope, objectives, and key findings.
- **Section 2** provides background on the role of DG resources in California; the use of SGIP DG performance data to address questions regarding the ability of DG resources to address critical issues in California electricity system; and the approach used in the DG Study.
- **Section 3** presents the results of the analyses, including conclusions.
- **Section 4** describes the sources of data used in the DG Study.
- **Appendix A** provides descriptions and the analyzes for the different distribution feeders examined in this study
- **Appendix B** is a more detailed explanation of the development of representative generator profiles and site demand profiles, and the relationship between generation profile and site demand at selected utility customer sites.

## 1.2 Key Findings

### *DG System Dispatch*

***Current Status of DG System Dispatch***

Due to the small size and widely dispersed nature of existing DG systems, utilities are not directly involved in the operation of DG resources. Instead, DG operation remains under the control of the customer. From the generation and demand data evaluated, operation of DG systems deployed within the SGIP appears to follow the customer's business cycle.

If the electric customer is an industrial or commercial business that operates 24 hours a day, the customer may elect to deploy a DG unit that operates in a baseload configuration. When the electric customer is a commercial business that operates during more typical daytime working hours, the customer can elect to deploy DG units that cycle their operation (i.e., ramp generation up or down) to meet demand during on-peak hours. For DG systems where the generation profile is controlled by outside factors (such as PV systems where the output is solely based on solar radiance), the customer is limited in the extent to which electricity demand can be addressed.

To evaluate the status of DG dispatch, we focused on generation technologies that could be controlled by the system owner. For the most part, these consisted of generation technologies such as ICE, fuel cells, microturbines and gas turbines. These generation technologies are used predominately in the CHP systems deployed under the SGIP. By the end of calendar year 2008, there were 1,275 DG systems operational in the SGIP, of which 391 were CHP facilities. Generation profiles for 149 of these systems (or approximately 38% of all CHP facilities) were examined and classified as baseload or non-baseload. Based on our analysis, we found:

- *CHP generators deployed under the SGIP can be successfully classified into baseload and non-baseload generation categories by type of generator technology, location, and application.*
- *The vast majority (nearly 89%) of the CHP generators examined fell into the baseload characterization, while the remaining 11% can be characterized as non-baseload generators.*
- *Fuel cells and gas turbines show clear classification as baseload generators, whereas IC engines and microturbines show generation profiles that can be characterized as either baseload or non-baseload. .*

Although we had limited facility demand data, we also examined the extent to which CHP generators designated as non-baseload could be dispatched to follow demand at the site.

- *By comparing generation profile data against site demand data, we found there was a high correlation between the demand profile and the generation profile. This indicated in those instances, the generator was able to successfully track and respond to changes in demand at the site. However, due to the small sample size of site demand data, we were not able to determine how many of the DG systems classified as non-baseload generators were actually acting in a load-following pattern.*

The ability of customers to dispatch DG to meet site needs is important. It is also important to understand the extent to which DG systems can be dispatched to meet distribution feeder peak demand. Based on restrictions of the SGIP, DG systems deployed under the program are sized only to meet customer demand. There is no over-sizing of DG systems in order to provide excess power to the utility grid. In addition, while there were 1,275 DG operational in the SGIP in 2008, these constitute a very small percentage of the overall generators that can be connected to a distribution system. The capacity of the generators also typically makes up a very small percentage of the peak demand capacity of the distribution feeder.

- *At present, DG facilities operating in the SGIP in California currently lack the ability to dispatch to address peak demand on distribution feeders. The degree to which the DG generation profile coincides with the feeder peak is unplanned and accidental. Moreover, due to the low penetration rate of SGIP DG systems on distribution feeders, the impact of even these coincidental overlaps is likely to be insignificant.*

***Improving the Dispatch of DG Systems***

As indicated above, some DG systems appear to have the ability to be dispatched to meet demand at customer sites. However, due to the currently low penetration of DG on distribution feeders, there is limited capability of these systems to provide utility benefit by addressing peak demands at the distribution level. Consequently, using power flow analyses and representative DG generation profiles, we simulated impacts associated with overbuilding of DG resources as well as blending of DG resources on distribution feeders. Based on those evaluations, we found the following:

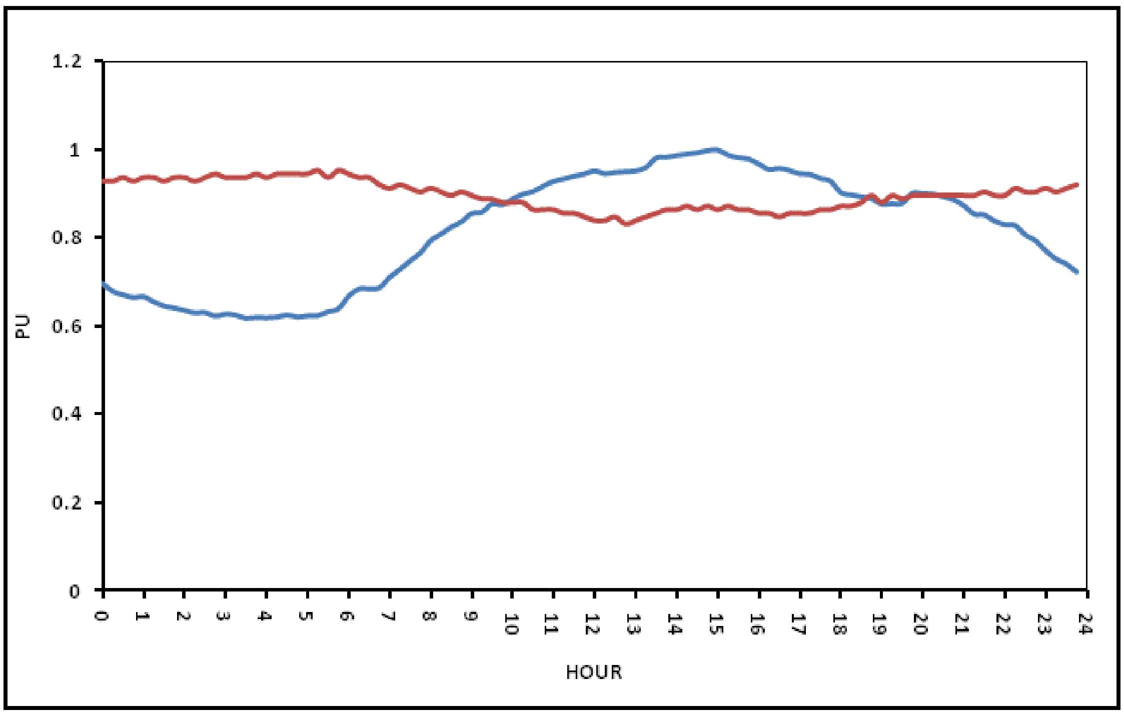
- *To provide utility benefits, DG capacity on distribution feeders must increase in size from kilowatts to megawatts. In general, the installed DG capacity per feeder should be in the 1 to 5 MW range so the DG systems provide excess power to the utility, which can serve other customers on the feeder or back feed into other feeders connected to the substation.*

- *By appropriate overbuilding or blending of DG resources, DG systems can potentially provide utility benefits by addressing feeder distribution peak demands; reducing distribution line losses; and acting as a possible reserve capacity.*

- *Currently, utilities lack the authority, training, or infrastructure to control these types of small and dispersed DG resources. Consequently, infrastructure and policies that provide appropriate price signals and DG dispatch control strategies must be developed and implemented if DG systems deployed in the future are to provide these utility benefits.*

Figure 1-1 through Figure 1-4 provide a visual example of the potential utility benefits associated with appropriate overbuilding and blending of DG systems. The DG system initially modeled consists of a 250 kW microturbine. The distribution feeder to which the microturbine is connected is a 12.47 kVA feeder rated at 3.6 MVA. The feeder experienced its peak 2008 demand of 8.9 MW on September 4, 2008. Figure 1-1 compares the feeder demand profile and the DG generation profile on the peak day.[8] The red line represents the generation profile for the microturbine. Note that the microturbine undergoes a slight de-rating during the peak demand period due to high ambient temperatures. At 250 kW, the microturbine by itself lacks the capacity to significantly impact the distribution feeder peak demand. In addition, due to the de-rating of the microturbine during the peak demand period, additional DG resources are needed to help address the feeder peak demand.

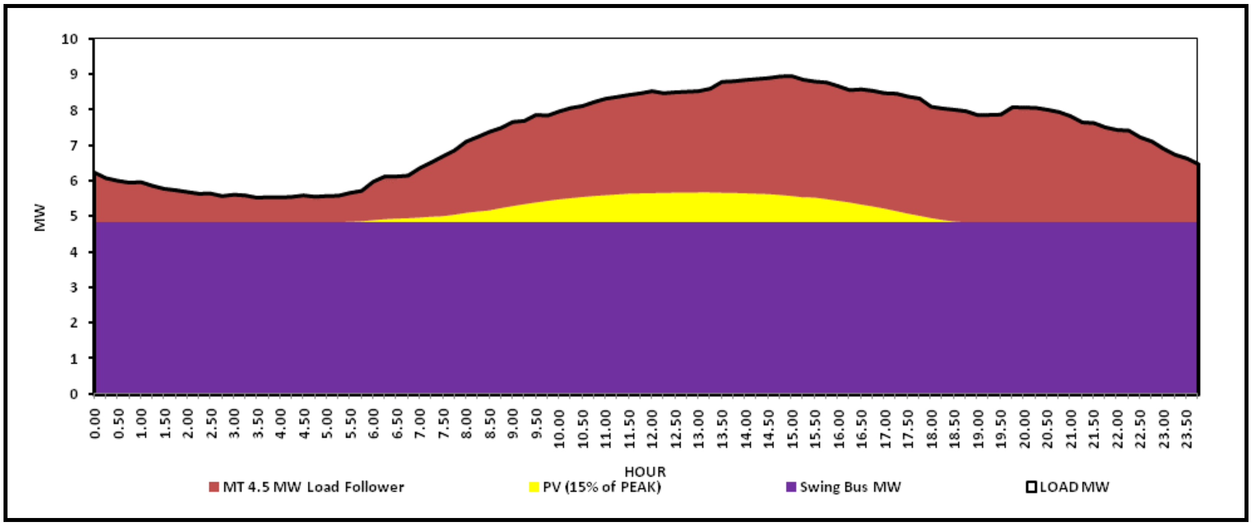
**Figure 1-1: Example of Generator Output Against Demand**




[8] Due to the significantly different capacities of the feeder demand and the microturbine system, the capacities are normalized using their maximum values and placed on a "per unit" or PU basis (as identified in the vertical axis).

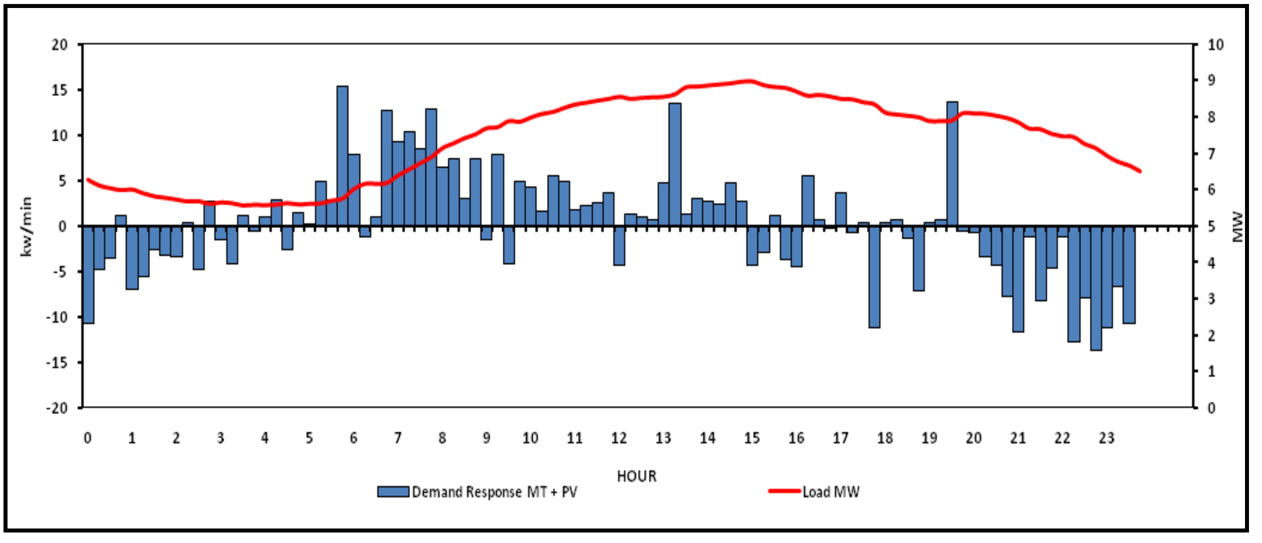
To help address the feeder peak demand, the capacity of the microturbine is increased in the model to 4.5 MW. In addition, PV capacity is added to the feeder. PV capacity is added as many distribution feeders are expected to see increased growth in PV with resulting significant capacity of PV on distribution feeders. In this example, PV capacity representing 15% of the feeder peak demand (i.e., approximately 1.3 MW) is added as part of the DG resource blend. Figure 1-2 shows the dispatch of the feeder Swing Bus located at the substation, the MT and a newly installed PV. The purple and red blocks represent the Swing Bus generator and MT, respectively, and the yellow block represents the PV generation. The Swing Bus is held at a constant generating value to reduce line losses and reduce ramping of utility-owned generation. The PV unit generates during the day time hours based on solar radiance and reduces the MT generation during the peak hours. In turn, the microturbine supplies generation to meet feeder demand in those time periods when the PV systems are not generating electricity.

**Figure 1-2: Dispatch of Swing Bus and DG Resources to Meet Feeder Peak Demand**



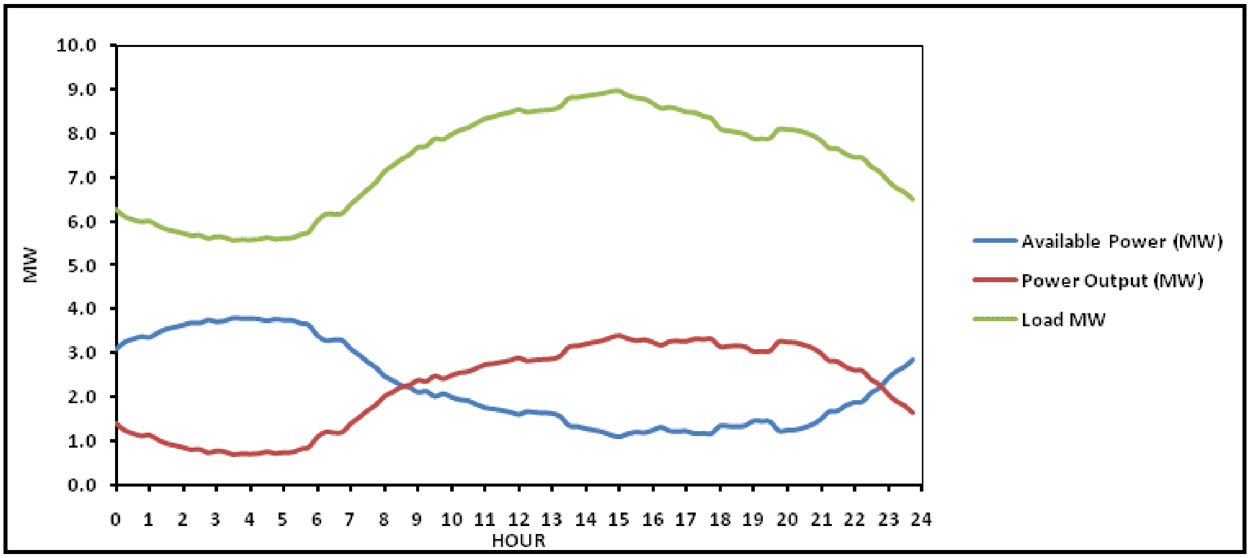
Blending DG resources to address feeder peak demand requires the DG resources have the ability to ramp up and down as needed to match feeder demand. In the example system, the DG resources consist of a virtual microturbine and virtual PV system. Because PV systems lack ramping capability, this means the microturbine system must meet the ramping profile of the distribution feeder. Figure 1-3 shows the ramping requirements of the microturbine during the example peak day. The microturbine ramp rate increases during the day but does not exceed 15 kW per min, which falls well within the microturbine ramp rates observed in the SGIP and within rated ramp rates for a microturbine. The maximum ramp up rate over a one-hour period is 917 kW and the ramp down rate is 820 kW.

**Figure 1-3: Demand Response Required for Microturbine Combined with PV**



If the utility has the ability to control dispatch of DG resources via price signals and control strategies, the microturbine system in the example can be dispatched to serve the variation in feeder demand instead of using utility generation and switching. Figure 1-4 shows the available excess power from the blended microturbine/PV systems that can potentially be used by the utility as reserve capacity.

**Figure 1-4: Available Power from the DG Generator Combined with PV**




In the example, two scenarios were modeled to estimate energy losses: 1) over sizing of the microturbine; and 2) blending the over sized microturbine with high penetration PV. Table 1-1 shows the average losses associated with the different configurations of DG resources in the example.

**Table 1-1: Average MW Losses for Each Type of Operation**

| Type of Operation | Average MW Loss | % Change From No DG |
|---|---|---|
| MW Losses NO DG | 0.044 | 0% |
| MW Losses Original DG | 0.041 | -7% |
| Losses Load Following 4.5 MW DG | 0.007 | -84% |
| Losses Non-Load Following 4.5 MW DG | 0.006 | -85% |
| Losses Load Following 4.5 MW DG + PV | 0.006 | -85% |

For the two original configurations where there was no generator added (all demand served by the Swing Bus) and the 250 kW generator added, the losses follow a similar profile over the 24-

hour period. The change in losses from no DG system to the originally added DG generator of 250 kW is approximately 7%. When the load-following 4.5 MW microturbine replaces the original 250 kW generator, the average loss is reduced by 84%. The Swing Bus provides a constant power; therefore, the losses are constant. When the generator is scaled up but follows a constant output profile, the losses change with the load. In this situation, the Swing Bus provides the small load changes and the average losses are reduced. Overall, the combined PV and 4.5 MW blend show an 85% reduction in losses relative to not having DG resources on the distribution feeder.

### *Locational Aspects of DG Systems in California's Electricity System*

#### ***Current Locational Aspects of DG Systems***

Currently, DG systems are installed without regard to reducing loading on distribution feeders or the transmission system. This is not surprising given the presently low penetration of DG resources within California's grid. Instead, most DG is installed by the customer primarily to reduce electric bills, provide generation to meet on-site demand or provide green power.

- *Results of T&D analyses conducted by Itron and others in 2006 indicated that DG systems could possibly provide reliability and congestion relief to California's T&D system. At present, due to their low penetration within California's electricity system and lack of a structured plan for using DG resources to reduce T&D loading, DG resources are limited in their ability to provide T&D benefits.*

#### ***Improving DG Locational Aspects***

Theoretically, locating DG resources on congested distribution feeders or transmission lines can help "un-load" the T&D system, thereby reducing congestion and improving system reliability. In particular, DG resources un-load the T&D system by providing generation close to the demand center, which acts to reduce transfer of power along the distribution feeders or transmission lines. Consequently, the ability of DG resources to provide utility benefits can be enhanced by strategically locating them on distribution feeders or transmission lines projected to have congestion or loading problems. Three different scenarios were modeled to evaluate the impacts of strategically locating DG resources: 1) the base case representing no new additional DG resources; 2) addition of 500 MW of new DG resources located at the top 200 substations showing projected congestion by 2020; and 3) addition of 1,000 MW of DG resources into the same 200 top substations. In general, our analysis found:

- *DG resources can be strategically deployed in ways and at locations that provide congestion relief and improved system reliability benefits within California's electricity system.*

- *"Look up" tables based on the modeling results of blended DG resources can be used in conjunction with the strategic location results to identify appropriate blends of DG resources on different classifications and locations of distribution feeders. The look up tables also provide utility planners with expected contributions of DG resources within the peak hour of the feeder. As such, these tools provide utility planners and DG developers with a new means for strategically locating DG resources in California that will have benefits to utilities as well as the DG industry.*

Figure 1-6 visually summarizes the DG locational value analysis results. The left graph is the base case without new DG resources. The red areas represent the best areas to locate new DG generation to help reduce congestion. The yellow areas represent the second best areas for locating new DG resources. White areas on the map signify that it is a neutral area. The blue shaded areas indicate poor areas in which to add DG resources. The blue and neutral areas should be avoided as there is already adequate to excess generation serving demand. The middle graph shows the congestion results after the installation of 500 MW of new DG. The right graph shows the congestion after installing 1,000 MW of DG. As more DG is installed on the system, the red and yellow shaded areas are eliminated or become lighter in color indicating that the addition of new DG is improving system reliability. However, higher penetrations of DG in the same area may have limited additional congestion reduction benefits.

**Figure 1-5: Summary Results for Optimizing DG Location for Transmission**

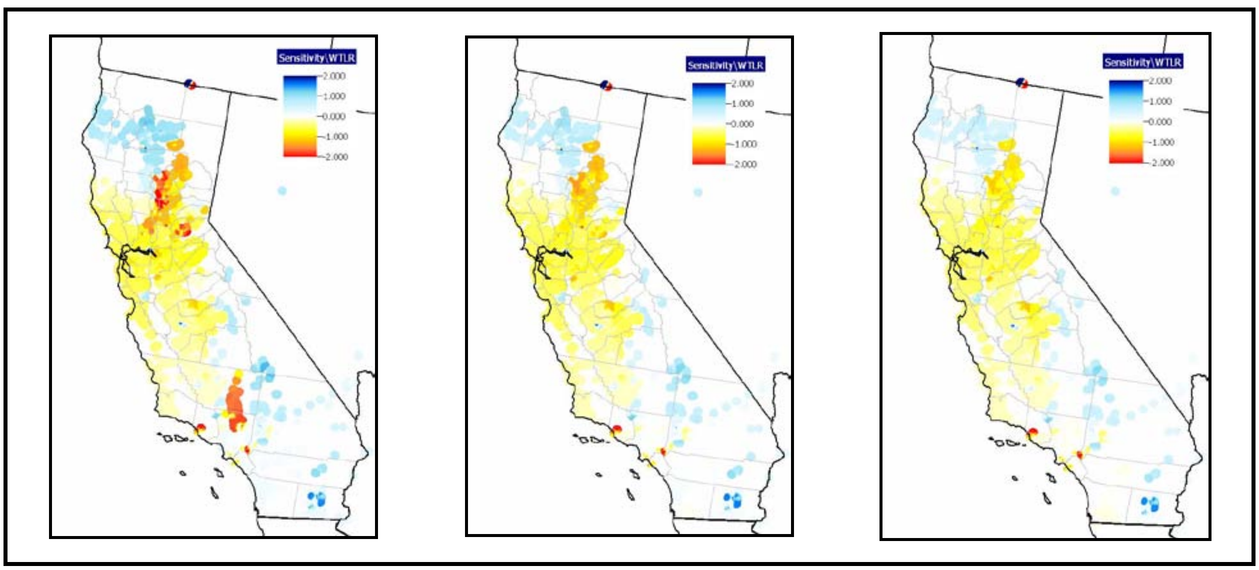


Table 1-2 is a listing of the strategic top two hundred substation locations for installing new DG resources to achieve T&D benefits. The table shows the climate zone and the potential capacity of new DG resources to be added to achieve the T&D benefits. This information should enable utility distribution planners to identify the feeders which will provide the greatest benefits from addition of new DG resources.

**Table 1-2: Top Bus Locations for Installing DG Systems**

| Utility | County | Climate Zone | Installed DG Capacity (MW) |
|---|---|---|---|
| PG&E | Alameda | 4 | 3.9 |
| | Butte | 11 | 125.0 |
| | El Dorado | 12 | 26.7 |
| | Modoc | 16 | 5.9 |
| | Placer | 11 | 12.5 |
| | Plumas | 16 | 5.7 |
| | San Joaquin | 12 | 2.5 |
| | Solano | 2 | 2.6 |
| | | 12 | 8.0 |
| | Sutter | 11 | 72.8 |
| | Yolo | 11 | 11.6 |
| | | 12 | 13.8 |
| | Yuba | 11 | 19.2 |
| SCE | Kern | 4 | 87.7 |
| | | 13 | 21.6 |
| | | 14 | 4.2 |
| | | 16 | 2.0 |
| | Los Angeles | 9 | 5.3 |
| | | 14 | 33.0 |
| | Orange | 6 | 5.4 |
| | San Bernardino | 9 | 10.6 |
| | San Joaquin | 12 | 2.0 |
| | Ventura | 6 | 18.0 |
| | | **TOTAL** | **500.0** |

Modeling results from the blended DG resources can then be used by DG developers and the utility for determining the best blend of DG resources to achieve the desired T&D benefits. Table 1-3 represents a "look-up" table of blended DG modeling results. The results are broken down by utility, location (inland versus coastal), customer mix and generator type. For example, consider a PG&E distribution planner looking at a congested feeder located in a coastal area, typically having a mid-afternoon peak and with a largely residential and commercial customer mix. A blend of DG resources that would potentially reduce feeder peak demand, increase system reliability and provide reserve capacity to the utility would consist of anywhere from 34% to 75% (i.e., percentage of feeder peak demand) ICE contribution; 8% to 13% PV contribution and 37% contribution from MT systems. During the typical peak hour, the ICE could be expected to provide 96% to 100% of its rated capacity to the peak demand; the PV system to provide 52% to 61% of its rated capacity to the peak demand; and the MT system to provide approximately 86% of its rated capacity to meeting peak demand.

**Table 1-3: Relationships Between Blended DG Mixes and Analyzed Distribution Feeders**

| Utility | PG&E | SCE | SCE | SDG&E | SDG&E | PG&E |
|---|---|---|---|---|---|---|
| Coast/Inland | Coast | Coast | Inland | Coast | Inland | Inland |
| Average Peak Time | Mid-Afternoon | Noon | Late Afternoon | Mid-Afternoon | Late Afternoon | No Data |
| Majority Customers | Residential/ Commercial | Residential | Residential | Residential/ Commercial | Residential/ Commercial | No Data |
| Contribution Scaled ICE to Peak | 34.3–74.9% | N/A | 42.50% | 26.90% | N/A | N/A |
| % ICE Operating at Typical Peak Feeder Hour | 96–100.0% | N/A | 94.20% | 71.00% | N/A | N/A |
| Contribution Scaled PV to Peak | 8.0–12.6% | 9.00% | 1.4–9.2% | 4.3–11.4% | 6.70% | N/A |
| % PV Operating at Typical Peak Feeder Hour | 52.1–61.0% | 60.80% | 9%–21.0% | 11.3–75.7% | 24.00% | N/A |
| Contribution Scaled MT to Peak | 37.30% | 44.60% | 81.8–86.0% | 54.4–64.4% | 49.7–72.7% | N/A |
| % MT Operating at Typical Peak Feeder Hour | 83.60% | 99.00% | 95.1–100% | 85.9–89.8% | 91.3–95.6% | N/A |

# 2

# Background and Approach

## 2.1 DG Resources in California's Electricity System

### *Development, Status, and Prospects of DG in California*

Distributed generation (DG) refers to electricity generation resources that are typically much smaller than utility generation systems and located on the distribution side of the transmission and distribution system. Many of the DG systems in operation today evolved in response to the Public Utility Regulatory Policy Act (PURPA) of 1978. The intent of PURPA was to help diversify the country's energy resources by establishing non-utility generation that would be more efficient, responsive, and diverse than utility generation technologies. PURPA spawned a wide variety of DG technologies ranging from fuel cells to wind turbines and powered by fuel types running the gamut from natural gas to solar energy.

DG systems can have a potentially significant impact on California's electricity system. There are numerous DG facilities currently operating in California. Solar PV systems represent a rapidly growing population of DG technologies within the state. There are over 50,000 solar PV systems installed in California representing more than 500 megawatts (MW) of generating capacity.[1] California is also home to a diverse fleet of natural gas-fueled DG systems. Natural gas-fired DG systems are often configured as combined heat and power (CHP) facilities to supply both electricity and process heat or cooling for on-site needs. Towards the end of 2009, CHP systems provided close to 9,000 MW of generating capacity to California's electricity system.[2] Somewhat less than 900 MW of this CHP capacity represents DG technologies smaller than 20 MW.

The contribution from DG and smaller-sized CHP is expected to grow significantly in California over the next decade. Since its inception in 2001, more than 1,300 DG systems contributing over 350 MW of generating capacity to the state's electricity system have been deployed under

---

[1] Itron, Inc., *Impacts of Distributed Generation Final Report,* for the California Public Utilities Commission, January 2010, pages 3-7.

[2] ICF, *Combined Heat and Power Market Assessment,* for the California Energy Commission, CEC-500-2009-094-D, October 2009, page 1.

California's SGIP.[3] In response to Senate Bill 412 (SB 412)[4], the SGIP is extended to January 1, 2016 and is being reconfigured by the CPUC. Additionally, the California Solar Initiative (CSI) has resulted in the growth of close to 25,000 solar PV systems, providing over 280 MW of rebated capacity.[5] The CSI will continue operation through 2016. Due to the combined operation of the CSI and SGIP, new DG generating capacity is expected to occur in the hundreds of MWs. Moreover, the California Energy Commission (CEC) has targeted significant growth in CHP and DG technologies over the next decade. In its 2007 Distributed Generation and Cogeneration Roadmap, the CEC targeted CHP and DG facilities to meet approximately 25% of California's peak electricity demand by 2020 (10% by DG and 15% by CHP).[6] More recently, the CEC has identified that the 2029 technical potential for small-scale CHP (i.e., CHP smaller than 5 MW in capacity) in California exceeds 18,000 MW.[7]

### *The Role of DG Dispatch in Meeting Energy Needs*

DG facilities can provide important benefits to both utility customers and utilities. DG systems can help customers meet on-site electricity needs, potentially reduce the need to purchase more expensive peak demand electricity, and possibly reduce demand charges. From the utility perspective, DG systems can potentially help defer the need to operate expensive peaking units and provide congestion relief to highly loaded distribution feeders and transmission lines. For both utility customers and electric utilities, DG systems may provide the greatest benefit when the generation profile closely matches the customer load profile. Establishing such a match requires a DG system to dispatch its generation either in concert with the fluctuating on-site energy needs of the customer or the utility. An objective of this study is to examine the ability of DG systems to dispatch their generation to meet customer demands throughout the day or to respond to demand needs by the utility as manifested by demand at the local distribution feeder. Additionally, this study examines the ability to improve the DG ability to dispatch generation to meet customer and utility demands.

### *Strategic Aspects of DG Location in the Grid*

Several studies have indicated there may be specific locations within California's electricity system where it would be especially beneficial to locate new renewable or DG systems. In 2005,

---

3 Itron, *CPUC Self-Generation Incentive Program: Ninth-Year Impact Evaluation Final Report,* June 2010.

4 SB 412 (Kehoe, October 11, 2009).

5 Itron, *CPUC California Solar Initiative: 2009 Impact Evaluation Final Report*, June 2010.

6 California Energy Commission, *Distributed Generation and Cogeneration Policy Roadmap for California*, CEC-500-2007-021, March 2007. The CEC projects 2020 peak electricity demand to be 70,776 MWs by 2020 and that DG systems will meet approximately 10% of the demand at over 7400 MW of generating capacity.

7 California Energy Commission, *2009 Integrated Energy Policy Report*, CEC-100-2009-003-CMF, page 101.

Davis Power Consultants (DPC)[8] conducted a study on behalf of the CEC to examine the feasibility of using renewable resources to both help the state achieve mandated Renewable Portfolio Standard (RPS) targets and help reduce transmission congestion. The DPC study showed that renewable generation located strategically onto California's electricity system could help achieve the RPS targets and improve transmission reliability 25% by reducing congestion.[9] Similarly, a recent study by the CPUC on the feasibility of achieving a 33% RPS target by 2020 suggests that strategically locating renewable DG onto the grid may be needed to meet the goal in the required timeframe.[10] An objective of this study is to investigate the likelihood that DG resources can be located strategically in a fashion to help reduce congestion and improve reliability of California's transmission and distribution (T&D) system.

### *DG Systems Deployed in the SGIP*

A variety of DG systems have been deployed under the SGIP, including solar photovoltaic (PV) systems; and natural gas as well as biogas-powered fuel cells, microturbines, internal combustion (IC) engines and small gas turbines. The manner in which these systems operate and their resulting generation profiles are based on a number of factors, including technical, economic, and environmental aspects. For example, some DG units (e.g., fuel cells) cannot make rapid changes in their generating capacity (i.e., have slow ramp rates) and so usually operate in a base-load configuration. Other DG units, which have fast ramp rates, may show generation profiles influenced by fuel costs, the purchase price of the generated electricity or by environmental restrictions.[11]

To better understand how DG systems in the SGIP address customer and utility electricity demands, we examined the way in which they generate electricity to meet peak electricity demand; respond to load changes at the customer site; or can potentially respond to a utility call for power.

---

8 Now part of BEW Engineering.

9 Davis Power Consultants, *Strategic Value Analysis for Integrating Renewable Technologies in Meeting Target Renewable Penetration,* CEC-500-2005-106, June 2005.

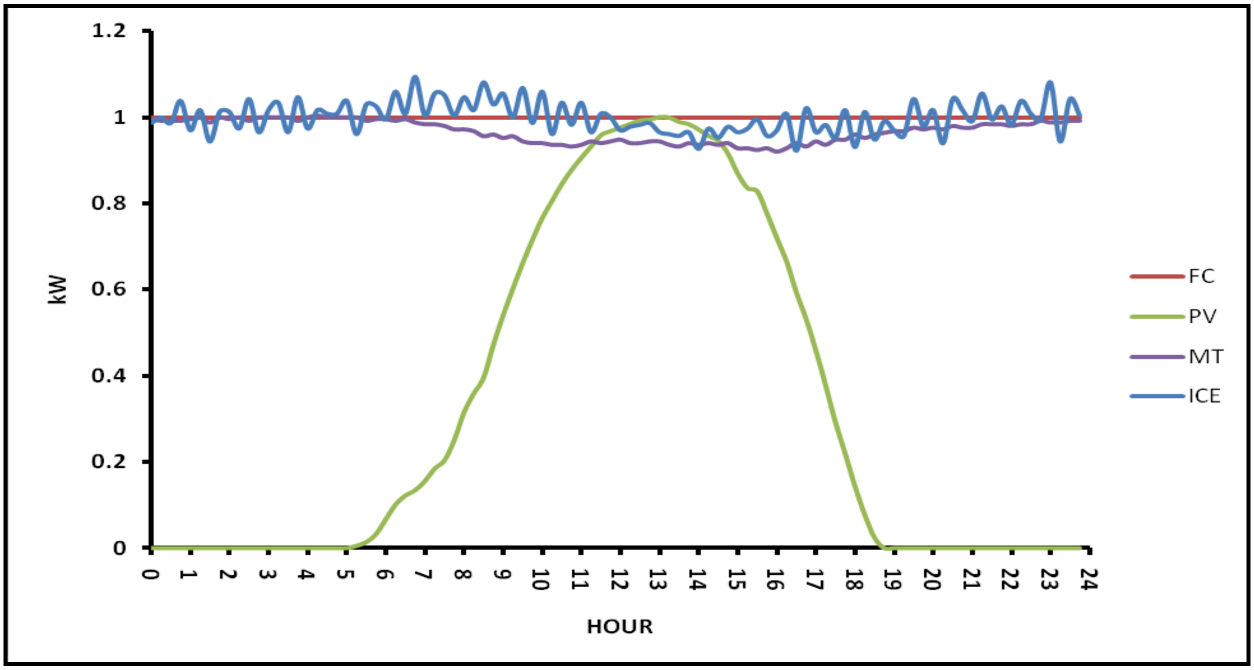
10 California Public Utilities Commission, *33% Renewable Portfolio Standard: Implementation Analysis Preliminary Results*, June 2009. However, the implementation aspects of integrating high penetration DG (solar PV) on the distribution system were not included in the CPUC analysis.

11 DG combustion units in particular may have curtailed operation at times to comply with air quality permit conditions.

***Peak Demand Generation of DG Systems***

DG technologies evaluated in this study included microturbines (MT), internal combustion engines (ICE), photovoltaic (PV) systems and fuel cells (FC). Each has unique generating characteristics. Figure 2-1 shows typical hourly generation patterns for these four SGIP generation resources. The generation capacity is normalized to 1 kW to allow comparison of the generation profiles of the different DG technologies.

**Figure 2-1: Typical DG Electricity Generation Profiles**




Microturbines are very small gas turbines that rotate at high speeds (e.g., 80,000 rpm) and have the ability to ramp generation quickly. Nonetheless, MTs typically operate at constant generating capacities. In addition, MT power output is sensitive to higher temperatures and MT output may be de-rated during peak load hours in response to higher ambient temperatures. The MT profile shown in the figure above represents a MT operating during the summer of 2008 in California's central valley. Although the generation profile is mostly constant, the power dips from 9 A.M. through 9 P.M. due to increasing outside air temperatures.

ICEs operating within the SGIP are typically natural gas or biogas-fired spark ignition systems. Spark ignition engines typically have rapid ramp rates and are not significantly influenced by outside air temperatures. Due to their fast ramp rates, IC engines can be used to address peak demand as well as follow customer load. The IC engine generation profile depicted in Figure 2-1 demonstrates the system being used in what appears to be a base-load pattern. However, note the power fluctuations within the hour-to-hour profile.

Fuel cells generate electricity based on an electrochemical process, much like a battery. Due to the sensitivity of fuel cell stacks to rapid changes in temperature, most stationary fuel cells have a high degree of thermal inertia, which prevents rapid start up and shut down. In general, fuel cells used in the SGIP act as base-load generating units. The very flat generation profile shown for the fuel cell in Figure 2-1 reflects the base-load nature of the system. The capacity of the deployed fuel cell is sized to help address a portion of the site's peak demand.

PV systems generate electricity based on solar irradiance patterns. As such, PV systems provide maximum output at the time of highest solar insolation, which may be different from when peak demand occurs at the customer site. Unless connected to electrical storage units, PV systems lack the capability to follow electrical load.

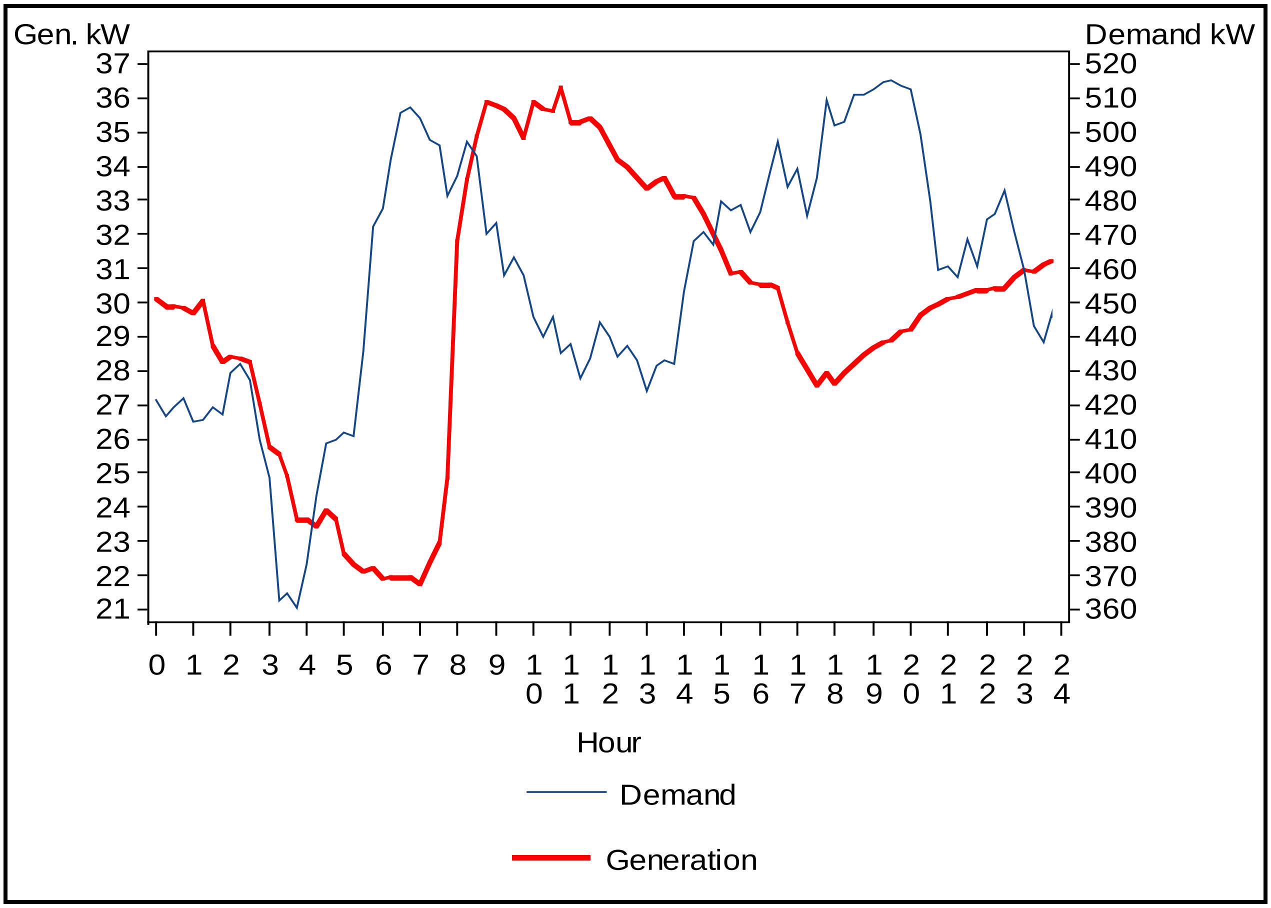
There are several ways to evaluate peak demand contribution from DG resources. Two common methods for calculating the peak demand contribution of DG resources are the Effective Load Carrying Capability (ELCC) and Resource Adequacy (RA) methods. ELCC requires extensive data and is normally calculated over a long time-period. RA is calculated for different seasons and covers shorter time-periods. We use a modified ELCC method in this study.[12]

[12] Typically, ELCC is used to predict the probability that a generation resource will be available in the future. We are examining past performance of generation resources. Consequently, we use a modified ELCC approach to measure the degree to which generation resources address the top 200 hours of peak demand at distribution feeders.

***DG Load Following Capability***

For many utility customers, electricity demand (load) changes throughout the day. Figure 2-2 is based on metered demand data from a facility housing an ICE unit and shows how electricity load can vary throughout the day. The generation profile of the ICE system used by the customer is also shown in the figure. In this particular instance, the ICE system appears to be lagging the electrical load.

**Figure 2-2: Characteristic Electrical Load Profile**



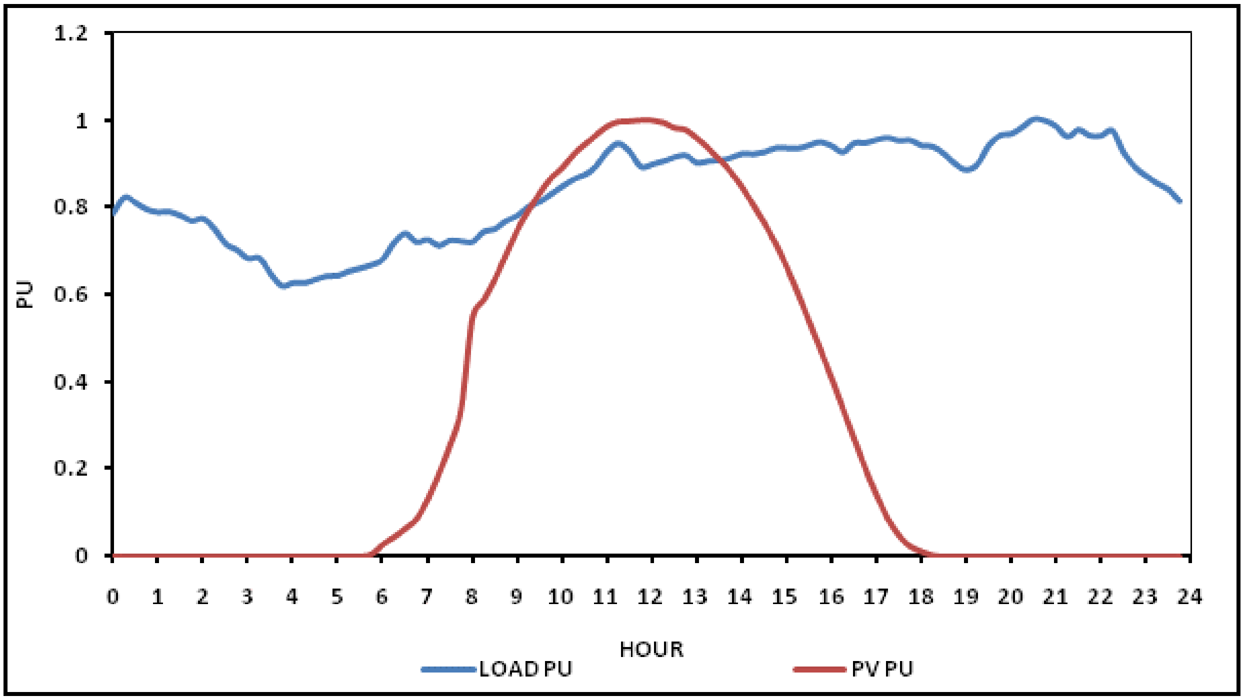

The ability of DG systems to provide load following capability depends on DG system characteristics such as heat rate curves, dispatch ability, ramp rates, minimum generation, and environmental constraints.

***Utility Call for Power***

As more DG enters the electricity system, its ability to affect or benefit utility operations increases. For example, high penetration of DG may potentially act as a generating reserve for the utilities if DG power is reliably available when needed. As part of this study, we investigate the ability and value of DG resources to respond to a utility call for power in two situations: 1) where DG capacity is overbuilt at the customer site; and 2) where there is very high penetration of DG capacity on a distribution feeder system. Appropriate overbuilding of DG capacity at the customer site may provide the facility with load-following capability and the ability to respond to a utility call for power. For example, assume the situation where electric customers on the same feeder or served from the same substation require 2 MW of generating capacity to meet demand but the customers actually install 3 MW of DG capacity. A percentage of the excess power can be used for load following while the remaining capacity can be used to respond to a utility call for power.

Due to the dispersed nature of DG resources, a utility call for power aimed at DG systems would likely address meeting peak demand occurring on specific distribution feeders. Climate zones, customer mix on a feeder and the time at which the feeder peak occurs will influence the peak demand contribution of DG resources. For example, a feeder located in a cooler coastal climate zone may have the feeder peak occurring in mid-afternoon. In this instance, PV generation located on the feeder will help address the feeder peak, as PV generation tends to be high from noon through the early afternoon. However, a feeder located in a desert or valley zone may have a peak occurring in the late afternoon or early evening due to air conditioning loads. An example of this type of situation is shown in Figure 2-3 where the feeder peak remains high throughout the evening. PV generation output is high until 2 P.M. but then drops rapidly as the sun begins to set. In this case, the PV system provides little help in addressing the late afternoon and evening peak demand.

**Figure 2-3: Load Profile Where PV has Minimal Effect on Peak Load**




Incorporating a combination of DG resources within a feeder may provide greater flexibility in matching generation profiles to demand profiles, while taking into account other factors such as environmental requirements, costs, and RPS targets. For example, a combination of high penetration of PV and MT generation could help address air quality and RPS targets, while still providing load following capability and excess generation to meet a call for power. In the situation described in Figure 2-3, adding MT generation capacity enables the combination of PV/MT to address the late afternoon and evening feeder peak.

We evaluate the ability for DG systems to respond to a call for power using time sequential power flow simulations that model any DG excess capacity as spinning reserves. In general, we do this by modeling generation connected at the substation level. For simplicity, all non-DG generation capacity[13] is treated as a virtual generator known as the Swing Bus. As the demand profile at the substation changes, power requirements above that which can be met by the Swing Bus represents a loss of generation within the time sequential capacity profile. As a result, the DG excess capacity held as spinning reserve is dispatched to serve the additional power needed to meet the demand.

[13] While other DG capacity may actually be on the distribution feeder, we have treated that capacity as part of the Swing Bus.

## 2.2 Analytical Approach

The objectives of this study are to investigate the ability of DG systems to dispatch their generation to help meet customer or utility electricity demands; and to determine if DG resources can be located strategically to help reduce congestion and improve reliability of California's grid. However, an overarching goal of this study is to help inform policy makers, the utilities, and the DG industry about ways to deploy increasing amounts of DG to help provide benefits to California's electricity system and its ratepayers.

### *Approach to Assessing DG Dispatch*

It is relatively straightforward to assess the ability of a single DG system to dispatch generation to meet on-site electrical demand or match the demand of the distribution feeder to which it is interconnected. However, California is home to thousands of DG systems located on thousands of distribution feeders. It is too costly and time consuming to obtain the data from these thousands of facilities and operations in order to conduct comprehensive one-to-one comparisons. In addition, thousands of one-to-one comparisons by themselves provide little insight into how to deploy future DG to better address customer and utility electricity demands.

Our analytical approach is based on "representative" data obtained from cross sections of metered data. The cross sections generally reflect the different DG technologies; IOU service territories; climate zones; distribution feeder characteristics; and customer applications[14]. The intent is to provide insights into how DG systems can address electricity demands to utility customers and the utilities in different situations and locations. Results are provided in "look up" tables.

Representative data were selected from metered generation data for DG systems deployed under the SGIP coupled with metered demand data from facilities housing the SGIP generation systems and metered demand data for the distribution feeders that interconnect the SGIP generators to the electricity system. For the purposes of this study, we used a sample of generation, facility demand and distribution feeder demand data from calendar year 2008. We limited the evaluation to the four summer months of June, July, August and September of 2008 as the focus of the evaluation was on addressing peak electricity demand[15]. SGIP generation systems were selected to represent a cross section of DG technologies and capacities; IOU service territory; and climate zones. In turn, distribution feeder data were obtained for selected distribution feeders based on a cross section of IOU service territory; customer mix; climate zone; and time of feeder peak (e.g.,

---

[14] Customer application refers to type of business classification used in the North American Industrial Classification System (NAICS).

[15] While some customers and distribution feeders may have peak demand occurring outside of the summer, a significant amount of peak demand in California occurs in the summer.

early afternoon, late evening, etc.). Metered demand data for facilities housing SGIP generation systems were selected to represent a cross section of DG technologies; IOU service territory; climate zone and type of customer application. Table 2-1 summarizes the data metered data available for the study. In general, there is a good cross section of metered generation data and distribution feeder demand data. However, only PG&E was able to provide electricity demand data for facilities housing SGIP generators.

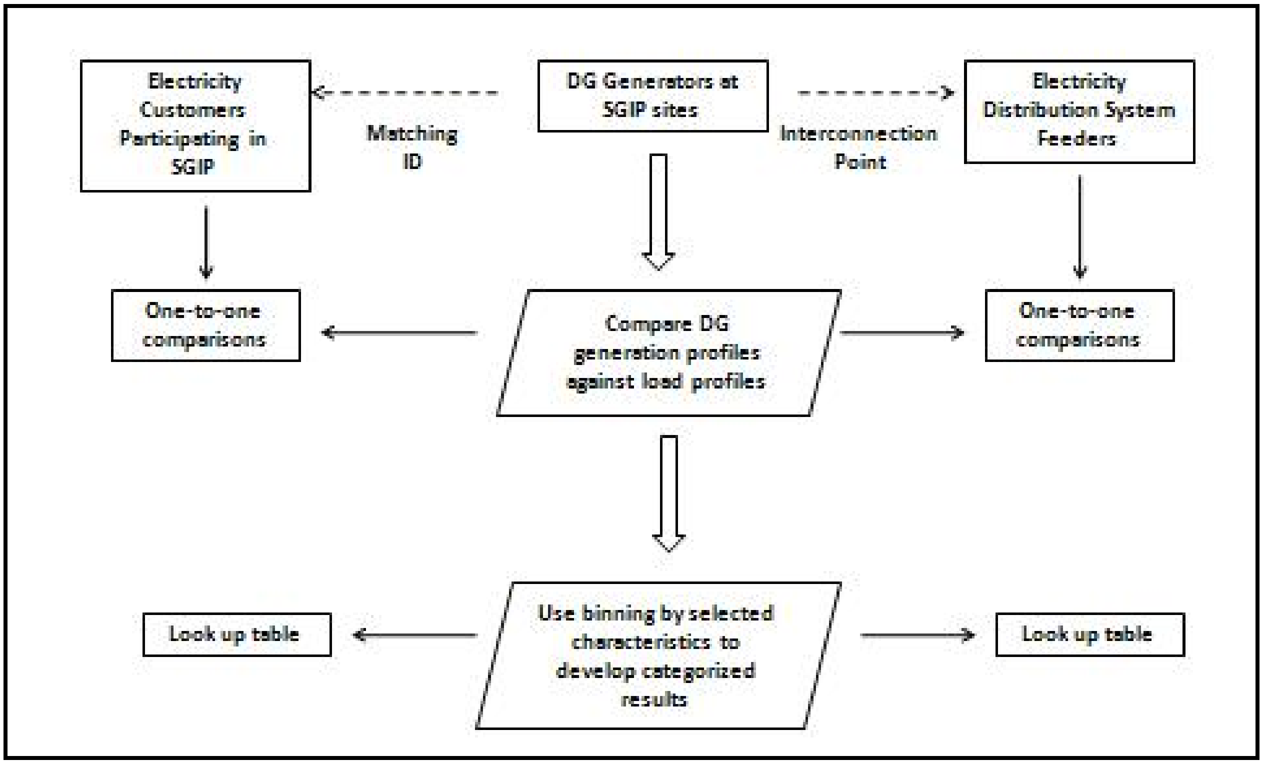
**Table 2-1: Summary of Data Provided for Study**

| Data Type | PG&E | SCE | SDG&E |
|---|---|---|---|
| DG Generation | Provided via SGIP metered data sets | | |
| PV | | | |
| ICE | | | |
| MT | | | |
| GT | | | |
| FC | | | |
| Feeder Demand (Load) | | | |
| Climate Zone | Yes | Yes | Yes |
| Customer Mix | Yes | Yes | Yes |
| Time of Peak | Yes | Yes | Yes |
| Customer Electricity Demand | | | |
| Climate Zone | Yes | N/A | N/A |
| Application (NAICS) | Yes | N/A | N/A |

N/A: Data were not provided

The analytical approach requires two separate activities in order to evaluate the DG dispatch capabilities and act as representative data sets. Figure 2-4 is an overview of the two main activities undertaken in the analytical approach.

**Figure 2-4: Overview of Analytical Approach**



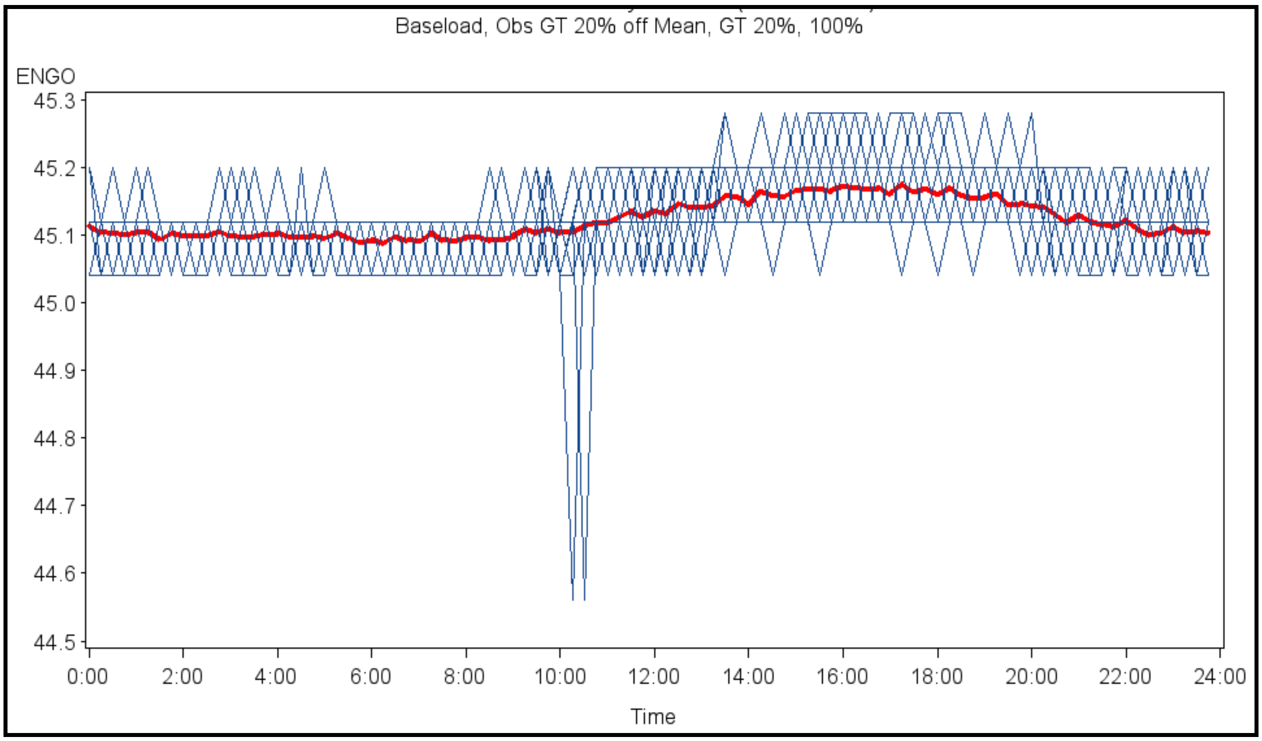

The first activity is assessing the ability of DG systems to address facility and distribution feeder loads. As noted earlier, this assessment uses metered data from DG facilities deployed in 2008 under the SGIP, metered demand data from facilities housing the SGIP DG systems, and metered demand data for the distribution feeders to which the DG systems are connected. The second activity is classifying the DG technologies, facilities, and distribution feeders by common characteristics (e.g., climate zone, time of peak, customer application, etc.). This classification makes it possible to identify how DG technologies (or combinations of DG technologies) can address customer or utility electricity demands in different situations and locations.

***Developing Representative SGIP Generation Profiles***

As of 2008, there were over 1,270 DG systems deployed under the SGIP. Metered 15-minute interval generation data were available for hundreds of these DG systems. However, not all DG systems had complete or nearly complete interval data sets for 2008. In addition, PV and wind systems cannot be used for load-following activities unless coupled with electricity storage. While we used metered generation for PV system generation profiles, our main interest was on developing representative generation profiles for DG systems with load-following potential. For the most part, these are generators contained in combined heat and power systems within the SGIP. Data sets for 198 SGIP CHP systems with different generator types were selected for study as they had interval data for over 90% of calendar year 2008.

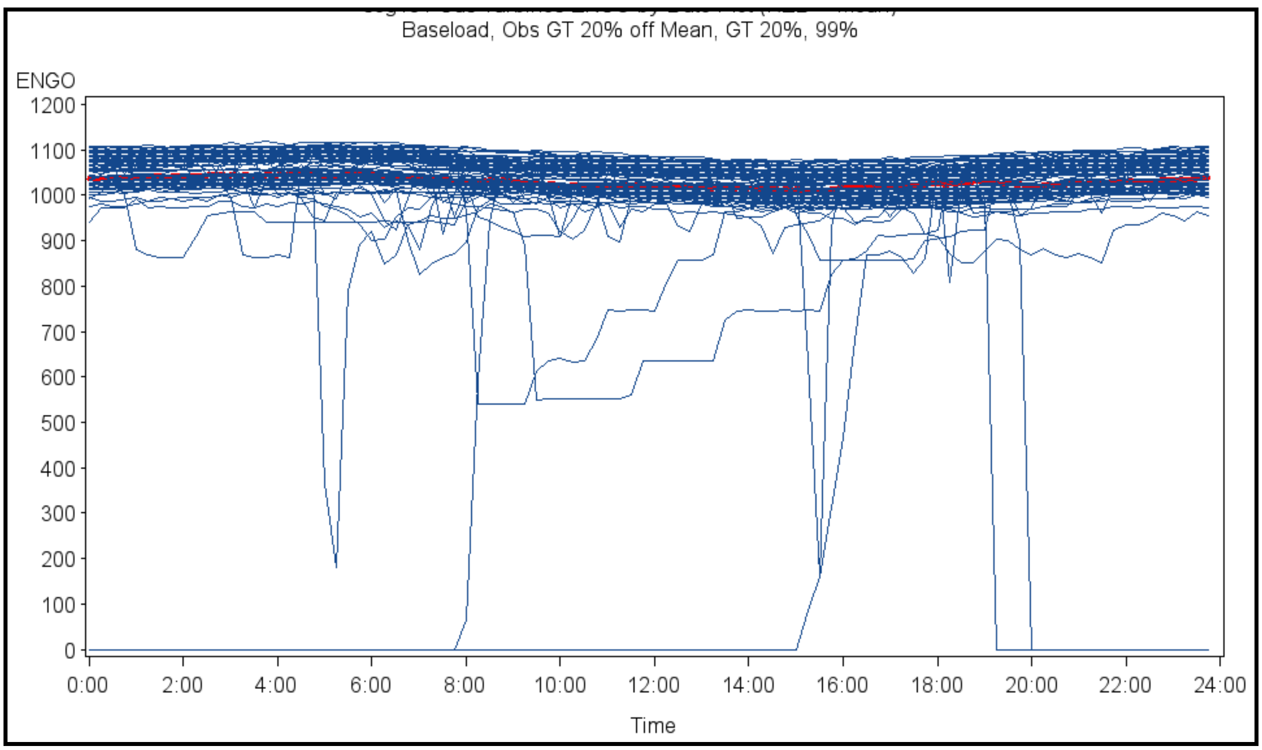
DG systems all operate differently and as a result, have distinct hourly generation profiles. In addition, hourly generation profiles vary from week to week throughout the year. A primary objective of this study is to evaluate the ability of DG systems to address peak electricity demand. In California, the highest peak electricity demand generally occurs in the summer months when there is increased use of air conditioning. Consequently, we focused on developing DG generation profiles for the four summer months of June, July, August, and September of 2008. In addition, we condensed DG generation profiles for those systems into a single representative day. Figure 2-5 is an example of a fuel cell generation profile condensed from the four summer months into a single representative day. The red line shows the average hourly generation profile for this particular fuel cell during the summer months of 2008. The generation values that fall above and below the average value reflect the deviation of generation from the mean value.

**Figure 2-5: Condensed Hourly Generation Profile for a Fuel Cell**



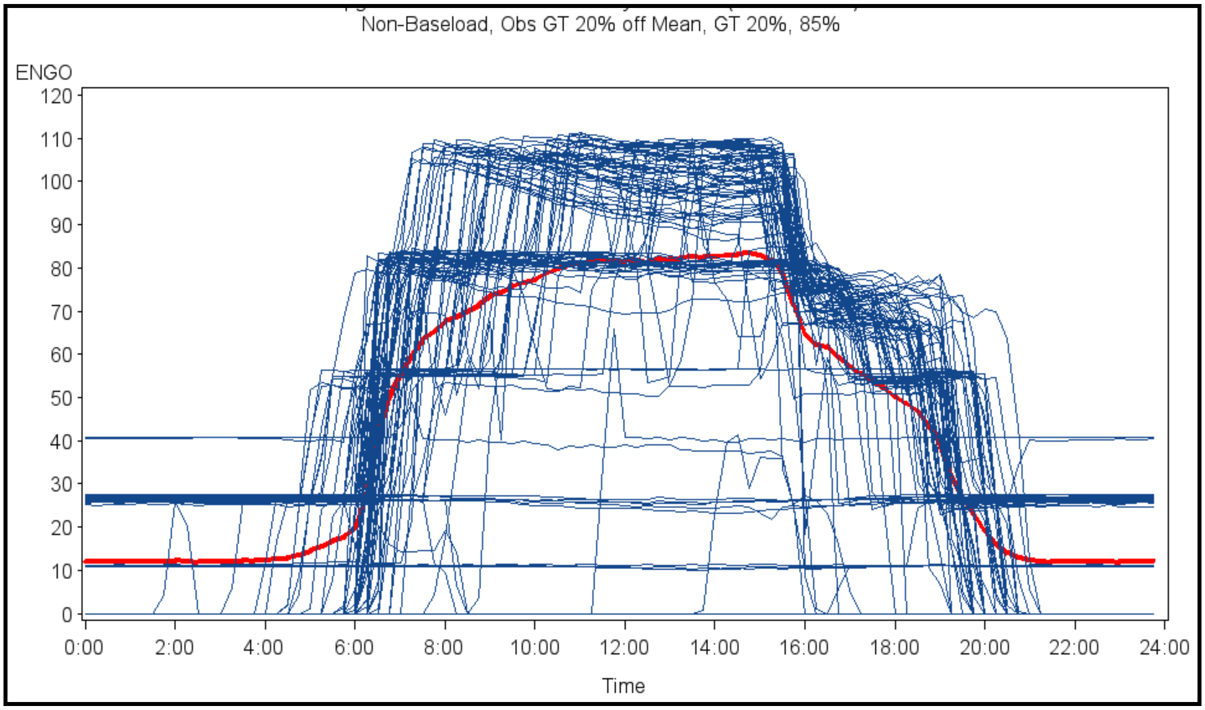
In addition to developing generation profiles for different DG technologies, we also wanted to determine if DG profiles could be categorized by "baseload" versus "non-baseload" patterns.[16] We used the variation of generation from the mean value to distinguish non-baseload type generation patterns. In particular, baseload generation could be expected to show a relatively flat generation profile, with a relatively small deviation from the mean value. Conversely, non-baseload generation could be expected to show a much greater deviation from the mean value. After examining a number of the DG generation profiles, we classified as non-baseload generation, those DG profiles for which at least 80% of the values exceeded the mean value by 20 percent. Figure 2-6 shows an example of a baseload generation profile categorized by this definition. Note that 99% of the generation values fell within 20% deviation from the mean value. Figure 2-7 shows an example of a non-baseload generation profile categorized by this definition. Note that in this instance, 85% of the generation values fell outside 20% deviation from the mean value.

**Figure 2-6: Example of Baseload Generation Profile**



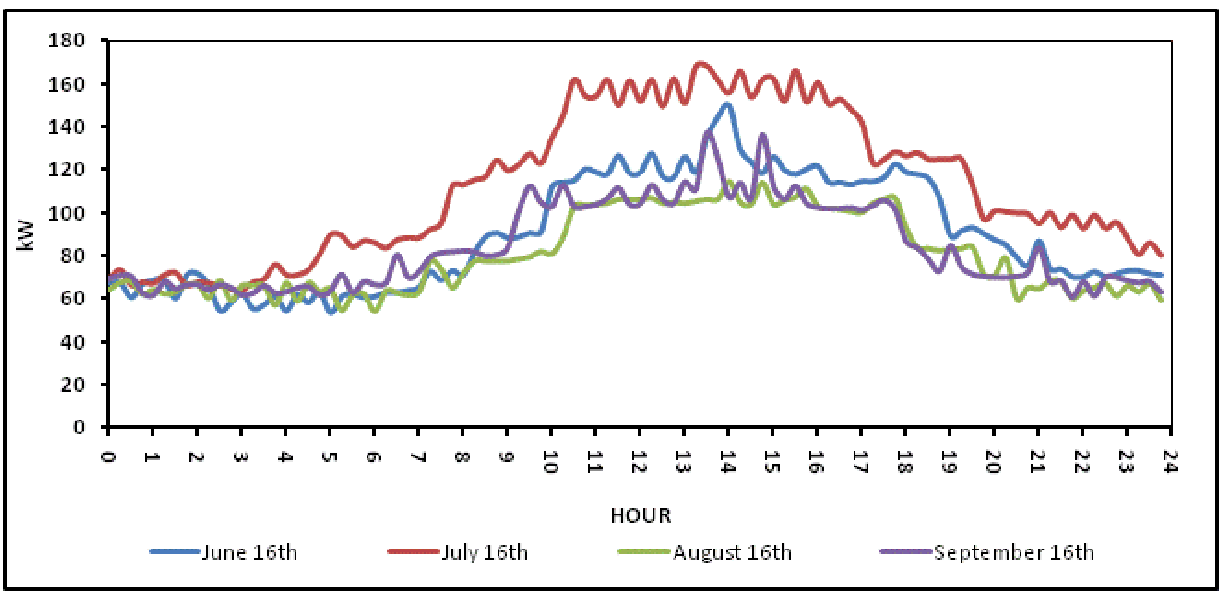

16 We used baseload and non-baseload categories in this instance because we were only looking at generation profiles and did not know if the DG system was used for load following or had been deployed as a baseload unit. In addition, in order to use this classification scheme for generalizing the results, we wanted to see how well the definition matched the actual designated use of the system.

**Figure 2-7: Example of Non-Baseload Generation Profile**




It was also important to determine operating capabilities for the different DG systems. In those instances, the team used hourly generation profiles taken from specific days for individual DG technologies. For example, Figure 2-8 illustrates the date-specific generation profiles used in assessing the operational capabilities of a microturbine system.

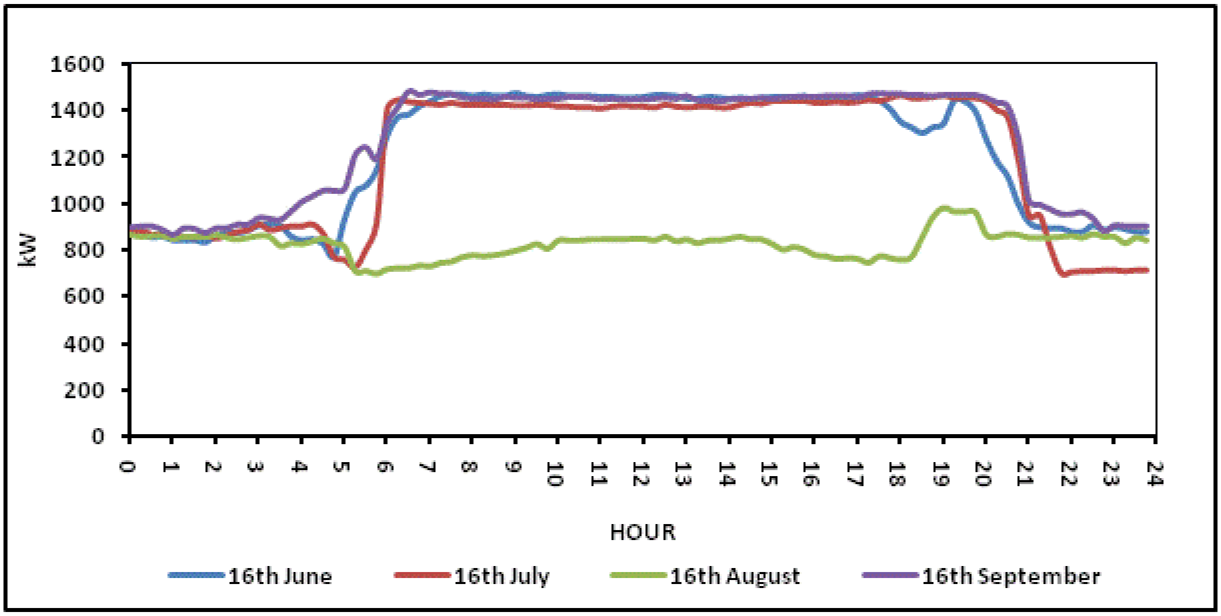
**Figure 2-8: Example of Generation Profiles Used to Determine MT Capabilities**



In this instance, the microturbine ramps up during a common day from early morning through the afternoon, and ramps down in the evening. The minimum operation of the MT shown in Figure 2-9 is approximately 60 kW, occurring near midnight. The maximum power, occurring near 1 P.M. is approximately 170 kW. The minimum power required from the MT on this day was only 35% of the maximum power delivered that same day. Note also that the MT power is fluctuating within each hour.

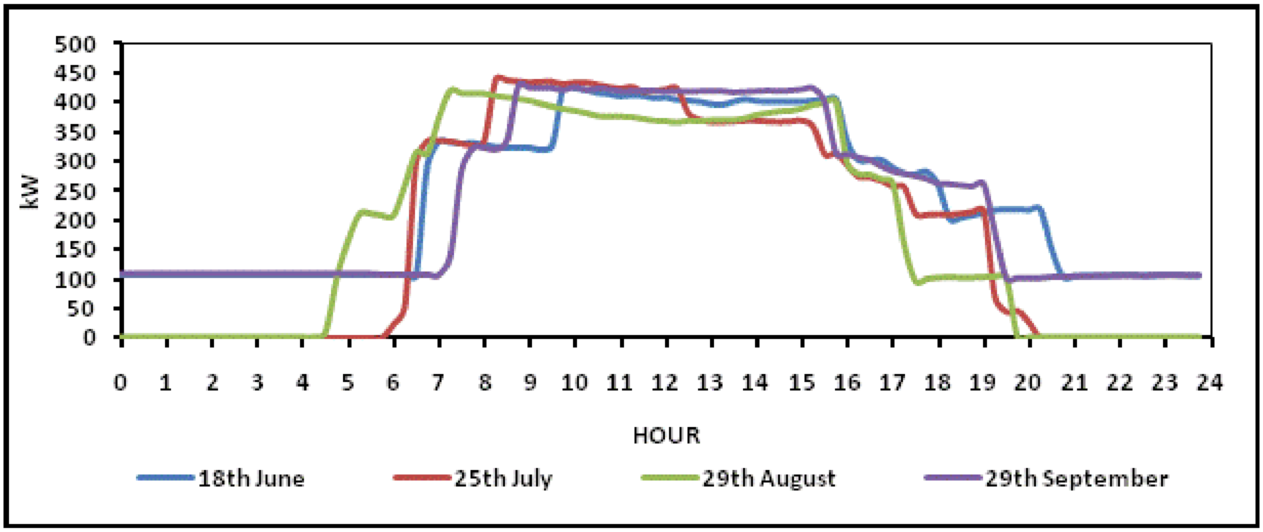
Representative load following capability was calculated in terms of demand response performance. Figure 2-9 shows an hourly generator profile for an ICE unit with a very high demand response rate. The maximum demand rate typically occurs around 6 A.M., represented by the near vertical generation profile. This generator is installed at an educational facility and rated at 1500 kW. The maximum measured demand response rate calculated from the 15-minute data is 69 kW per minute.

**Figure 2-9: Example of Maximum Ramping of ICE**



Similarly, Figure 2-10 shows the maximum ramping capability for a microturbine system. In this particular instance, the observed maximum demand response as calculated from the 15-minute data was approximately 25 kW per minute. This microturbine was installed at a commercial facility.

**Figure 2-10: Example of Maximum Ramping of MT**




While the ICE result was within acceptable range of rated ability, the MT ramp rate was well below that expected for microturbines. The observed value was taken from a load following unit. Therefore, we concluded the rate was not representative of microturbine ramping abilities. We believe the unit was possibly following a particular load, and not operating at maximum capability.

***Developing Representative Profiles for Type of Facility***

In order to have the ability to translate DG generation profiles into other situations, it was also necessary to develop representative profiles by the type of facility application. We used North American Industrial Classification System (NAICS) codes to classify the facilities housing the SGIP generators. Our intent was to determine if we could see differences in generation profiles between occupancy-oriented facilities (e.g., schools, office buildings, and hotels) and process-oriented facilities (e.g., manufacturing facilities). In general, we anticipated that occupancy-oriented facilities might show generation profiles with a peak if the generation system was load following to meet increased demand from higher HVAC loads.

Figure 2-11 shows a non-baseload generation profile for a facility identified as an office space. The ramp up of generation in the early morning followed by a generally flat profile during the day, with a ramp down in the late evening suggests that the generator was used to offset lighting and HVAC demands. I

**Figure 2-11: Non-Baseload Generation Profile for Occupancy-Oriented Facility**

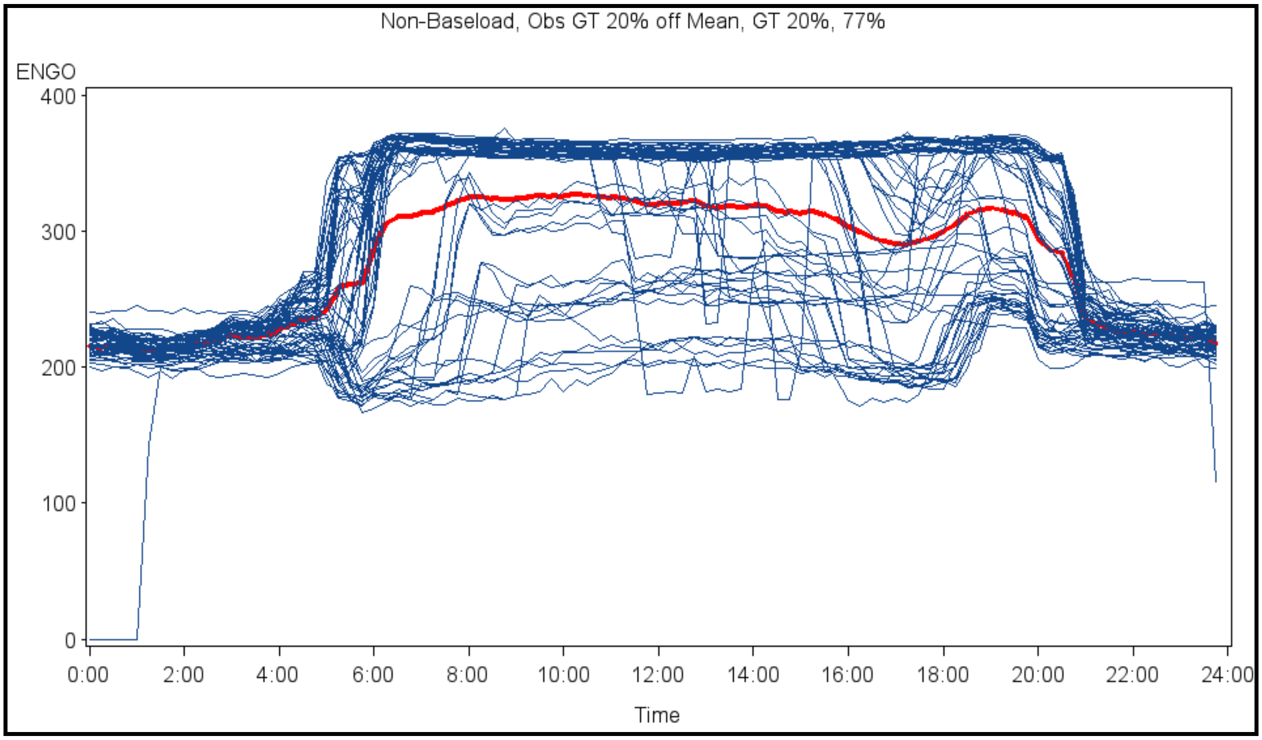
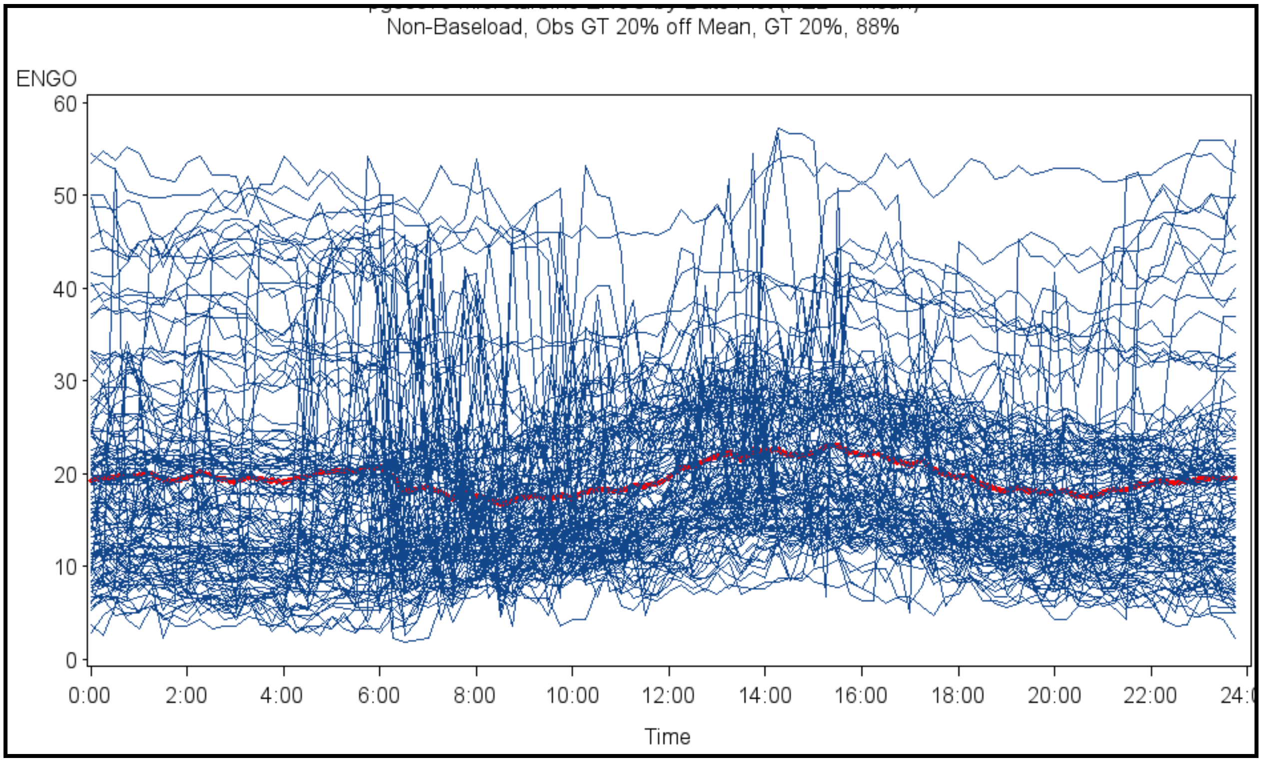


Figure 2-12 shows a non-baseload generation profile for a facility identified as a waste remediation processing facility. The significant fluctuation in the generation profile throughout the day suggests the generator is responding frequently to meet electricity demand from processes associated with the waste remediation application. Both of these examples indicate the use of occupancy-driven and process-driven categories appropriately categorize responses of DG generators to demand at different types of customer sites.

**Figure 2-12: Non-Baseload Generation Profile for Process-Oriented Facility**

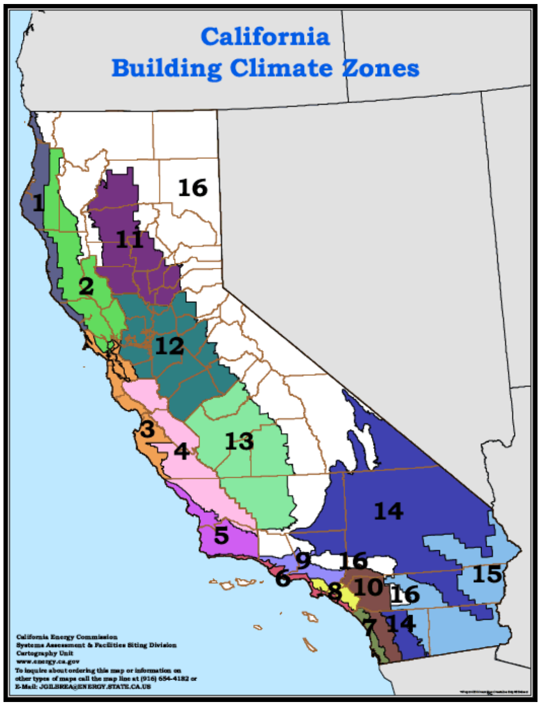



***<u>Selection of Representative Distribution Feeders</u>***

Representative distribution feeders were selected for each Investor Owned Utility (IOU) based on the type of DG technology, climate zone, and customer mix on the feeder. The feeder selection was limited to those distribution feeders which were interconnected DG systems with historical 15-minute interval generation data and for which the IOUs had corresponding 15-minute feeder demand data.

A cross section of distribution feeders was based on climate zones. The CEC has developed sixteen designated building climate zones ranging from coastal, valley, desert, and mountain climates. Figure 2-13 is a map of California's 16 building climate zones.

**Figure 2-13: California Building Climate Zones**




The location of DG technologies in different climate zone can affect the generation profile of the DG system due to local weather conditions (e.g., ambient temperatures, cloudiness, and rainfall). For example, microturbines located in hot desert climate zones may show de-rating during the highest daytime temperatures due to their sensitivity to ambient air temperatures. Similarly, PV generation profiles can be affected by fog or cloudy conditions associated with coastal climate zones.

As part of the feeder selection process, the IOUs were provided with a list of SGIP generators for which there was complete 15-minute interval generation data for 2008. The IOUs determined the feeder that served the facility and the availability of historical feeder load data. Each IOU was asked to select ten feeders for which they could provide information. For each feeder, 15-minute feeder demand data was requested for the months from June through September of 2008. In addition, the IOUs were requested to provide the feeder customer mix (residential, commercial, industrial) along with the feeder one-line diagram, line characteristics, and GIS data. During the course of the feeder selection process, the IOUs discovered missing or unavailable data for some of the ten feeders. As a result, the actual number of feeders for which the IOUs could provide data was reduced to six (6) feeders for PG&E, six (6) feeders for SCE, and five (5) feeders for SDG&E. Table 2-2 summarizes the distribution feeders for which the IOUs supplied feeder demand data, along with the associated customer mix and climate zone. Table 2-2 also shows the type of SGIP generator types interconnected to the electricity system via the selected feeders.

**Table 2-2: Examined Distribution Feeders and Feeder Characteristics[17]**

| Utility | Feeder | Climate Zone | Commercial Load | Industrial Load | Residential Load | SGIP Generator Type |
|---|---|---|---|---|---|---|
| PG&E | PG&E A | 3 | 11% | 2% | 82% | 3-PV; 1 ICE |
| | PG&E B | 3 | 54% | 38% | 7% | 1-PV |
| | PG&E C | 3 | 11% | 2% | 87% | 1-ICE |
| SCE | SCE A | 8 | 99% | 1% | 0% | 1-MT |
| | SCE B | 9 | 98% | 0% | 2% | 1-MT |
| | SCE C | 13 | 56% | 43% | 1% | 1-ICE |
| | SCE D | 13 | 94% | 6% | 1% | 1-PV |
| SDG&E | SDG&E A | 7 | 57% | 16% | 27% | 3-PV |
| | SDG&E B | 7 | 76% | 0% | 24% | 3-MT |
| | SDG&E C | 7 | 52% | 48% | 0% | 1-PV; 2-FC |

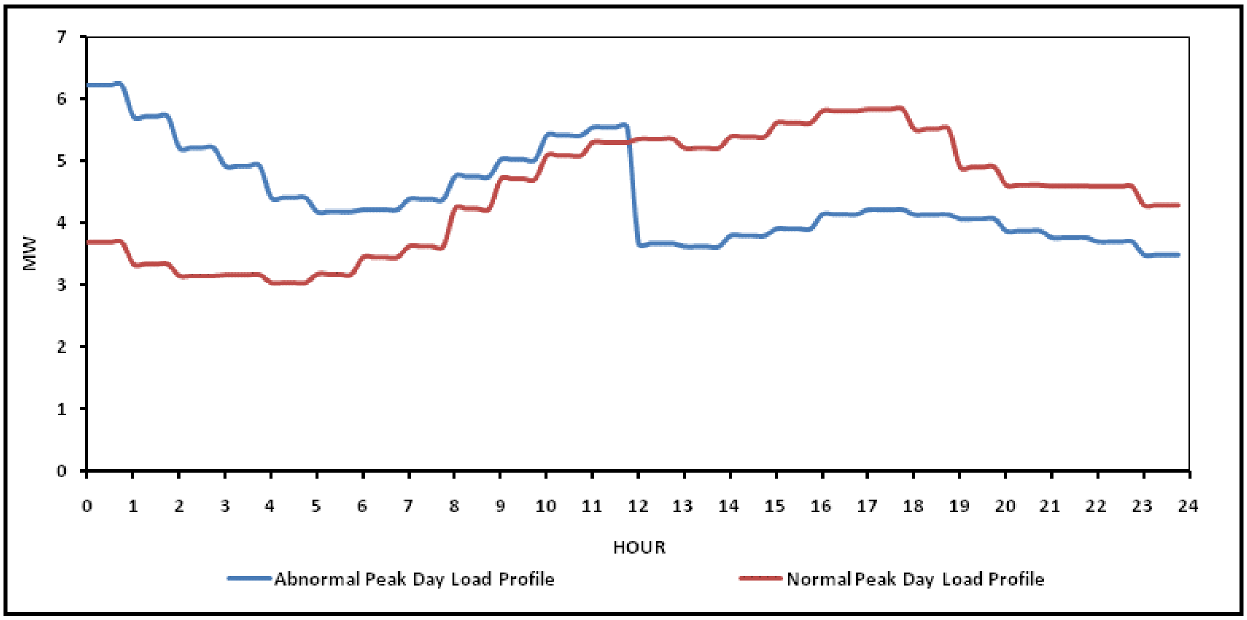
***Characterization of Representative Distribution Feeder Profiles***

As with generation profiles, we wanted to develop representative distribution feeder demand profiles that could later be used in a "look-up" table. Distribution feeder demand data was provided by the utilities for the four selected summer months in 2008. The first-cut analysis involved narrowing the analysis range to the peak load day for the distribution feeder. The peak day was selected from the provided data as the day on which the highest demand occurred. However, the day selected for analysis must have corresponding complete and correct DG generation data. In some instances, DG generation data was missing from the feeder peak day in 2008 or had zero values. Therefore, we broadened the analysis from just the peak day to the top 200 hours of demand for the distribution feeder. We also checked generation data from 2007

[17] Note that percentages of customer mix may not add to 100%. Customer mix information from the IOUs listed "other" without explanation. As a result, we did not include this data into the analysis.

and 2009 for those generation data that showed zero values to ensure we had representative generation data. Figure 2-14 illustrates the selection of a peak feeder day. The blue line indicates the demand profile for the feeder at what appears to be the day with highest demand. However, at approximately 11 A.M., the demand decreased dramatically by 2 MW over 15 minutes; a demand change of 133 kW per minute. This change could represent a large piece of machinery switching on and off at a particular time but might also represent abnormal sensor data. In comparison, the red line in the figure shows the DG generation profile on a different day, which does not show a dramatic drop at 11 A.M. In these situations, we compared generation data for the DG unit against the top 200 hours of the feeder demand; and compared the 2008 DG generation data against 2007 and 2009 DG generation data. If the DG generation profile for the 2008 feeder peak was significantly different from DG profiles from 2007 or 2008, we used the developed 2008 representative generation profile in lieu of the actual 2008 profile for developing generation blends on the peak day. By using the 2008 representative DG generation profile, this allowed us to capture the lower performance of the DG system without biasing the results to an abnormally low generation profile that occurred on only one day.

**Figure 2-14: Selection of Peak Day Generation Data**



After selection of a representative peak day for each feeder, the demand profiles were characterized by time of peak, customer mix, location, and climate zone, as shown in Table 2-3.

**Table 2-3: Time, Magnitude, and Date of Peak Load for Selected Feeders**

| Feeder | Coast/Inland | Climate Zone | Time of Peak | Date of Peak | Peak MW |
|---|---|---|---|---|---|
| PG&E C | Coast | 3 | 12:00 PM | 7/8/2008 | 8.56 |
| SCE A | Coast | 8 | 12:00 PM | 6/23/2008 | 8.16 |
| PG&E D | Coast | 4 | 12:30 PM | 5/14/2008 | 5.79 |
| SDG&E B | Coast | 7 | 1:45 PM | 8/7/2008 | 8.00 |
| SDG&E C | Coast | 7 | 2:00 PM | 8/8/2008 | 4.83 |
| PG&E B | Coast | 3 | 2:30 PM | 10/23/2008 | 8.48 |
| SDG&E D | Inland | 10 | 4:15 PM | 6/21/2008 | 8.24 |
| SDG&E A | Inland | 7 | 5:15 PM | 7/18/2008 | 4.02 |
| SCE B | Inland | 9 | 5:30 PM | 9/7/2008 | 5.60 |
| SCE C | Inland | 13 | 6:00 PM | 7/15/2008 | 5.80 |
| SCE D | Inland | 13 | 7:00 PM | 6/13/2008 | 6.36 |
| SDG&E E | Coast | 7 | 7:30 PM | 9/30/2008 | 8.24 |
| PG&E A | Coast | 3 | 8:00 PM | 3/15/2008 | 10.91 |

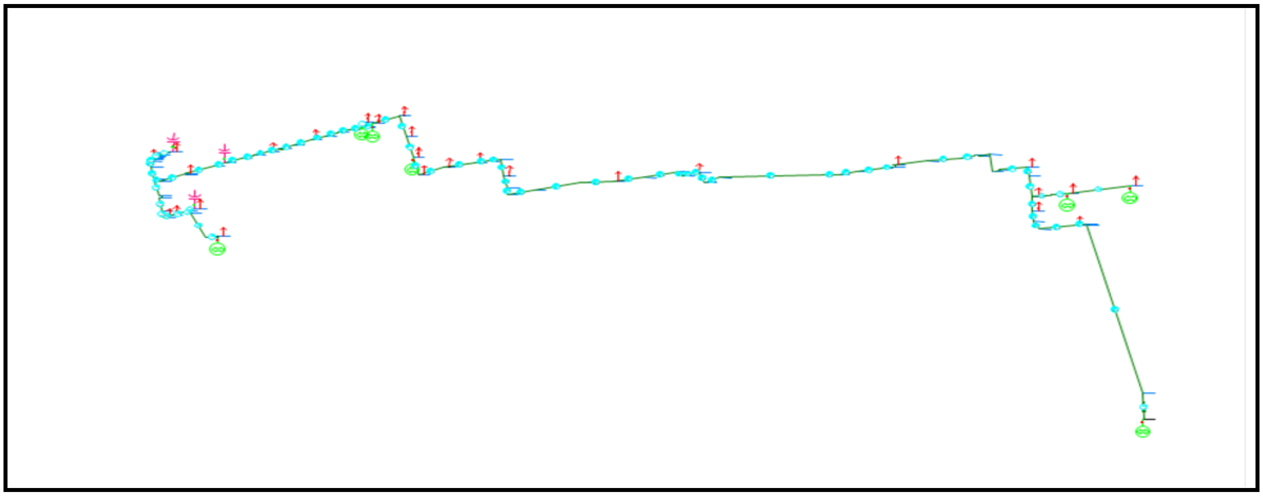
By referring to the customer data contained in Table 2-2, it is possible to identify the relationship between the time of peak and the customer mix. In general, the primarily residential feeders peaked at either midday or in the evening during the four summer months of 2008. This peak time could be indicative of times when air conditioning load was present, or when people were at home in the evening. Inland feeders tended to peak in the late afternoon. Coastal feeders peaked mostly in the early afternoon. Feeders with a large percentage of industrial facilities were found to often have widely varying peak times over the four-month period, due to manufacturing and other industrial schedules. In general, feeders with large numbers of industrial facilities were not found to follow a fixed pattern. Feeders with a majority of commercial facilities peaked in the middle of the day.

***Development of Power Flow Data Sets***

Direct comparisons between DG generation profiles and feeder demand do not by themselves indicate the possible impacts of increased DG on the feeder. Consequently, power flow simulations were used to examine how different quantities and types of DG may affect the distribution feeders. There were two simulation models considered for use in conducting this analysis: the SynerGEE distribution software and the Power World transmission software. The Power World software was selected as it provided a good fit between the feeder characteristics and objectives of the study. In addition, the Power World software provided an easier method for simulating contingency conditions, ramp rates, and time sequential demand and generation levels.

In order to protect confidentiality of feeder and generation data, all simulations were sanitized to remove references to location and feeder numbers. A sample sanitized feeder circuit is shown below in Figure 2-15. A feeder contains hundreds of single-phase and three-phase transformers of various sizes. The actual customer demand served by each line transformer does not equal the transformer nameplate rating. Because the 15-minute demand data points is simulated over a selected time period such as one day, one week or one month, the assignment of 15-minute demand data to hundreds of transformers fell outside the scope of this study.

**Figure 2-15: Sanitized Sample Feeder Circuit**

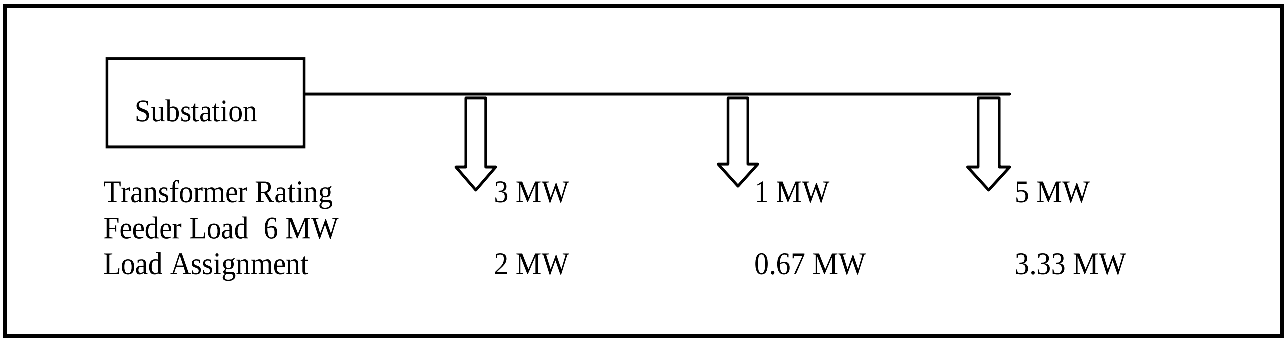


We also aggregated the individual transformers specified in the utility one-line diagram into larger "virtual" demand pockets. This aggregation reduced the number of transformers to be simulated to a manageable number. Depending on the location of the DG system on the feeder, the feeder system beyond the DG location can be converted to an equivalent load. As a result, the capacitor banks located between the substation and the DG system remain in service at the rated values. If there are other DG generators on the feeder for which there is no metered generation data, the generators are modeled in the open position or non-generating position.

***Treatment of Aggregated Feeders***

A load[18] value is assigned to each aggregated transformer. The criteria used to assign load to each aggregated transformer prorates the load based on the ratio between the metered feeder load and the total transformer capacity. Figure 2-16 is an example of how an aggregated transformer is treated in the model.

**Figure 2-16: Example of Aggregated Transformer**




In this example, there are three transformers in the part of the feeder being examined. The total feeder load for this one hour is 6 MW but the total aggregated transformer capacity is 9 MW. The ratio of feeder load to transformer capacity is 0.67. Each individual transformer capacity is multiplied by the ratio to obtain the load assigned to each transformer. For example, the first transformer has a capacity rating of 3 MW. The load assigned for the first transformer is consequently 2 MW (i.e., 3 MW times 0.67). This prorating is required because the utility does not have the 15-minute loading on each individual transformer but only on the total feeder.

Since Power World simulates 12 kV feeders, there must be at least one generating resource on the feeder called the “Swing Bus”. In a normal power flow data set that is significantly larger than a single feeder, the Swing Bus dispatches to serve all un-served load during contingency analyses. The Swing Bus generator is normally located remote from the utility system under study. If the Swing Bus is too close to the load centers, the Swing Bus could pick up more load and cause local transmission lines to overload.

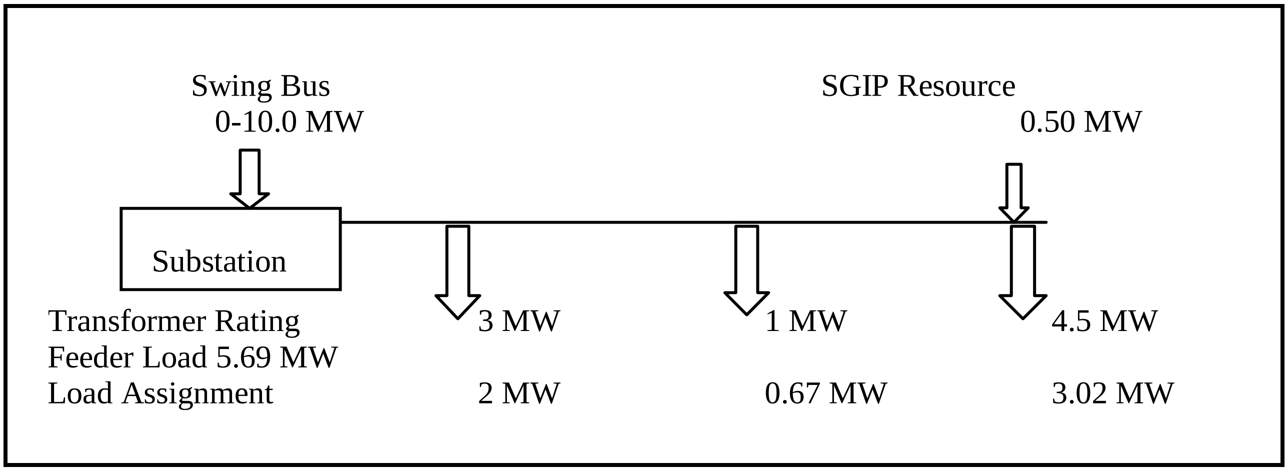
Because each feeder is simulated with no interconnections to other feeders, the Swing Bus is located on the substation bus serving the feeder load. The generator size is larger than the summation of the feeder load and the DG resource. The one feeder now includes the Swing Bus and the DG resource. As new potential DG resources are added to the feeder, the dispatch

[18] Load and demand are used interchangeably within this study when discussing distribution feeders. In general, load refers to demand whereas we use generation exclusively to refer to the generation profile.

between the Swing Bus and the DG resources becomes more complicated. As contingency analysis is completed, the Swing Bus attempts to pick up the load because it is located on the feeder. The Swing Bus is adjusted such that the DG resources are the first to dispatch.

Figure 2-17 shows an example of the Swing Bus modeling.

**Figure 2-17: Example of Swing Bus Modeling**




In this example, the Swing Bus can operate from 0 to 10 MW. In addition, there is a 0.5 MW PV system installed on the feeder. The PV system acts to reduce the needed transformer rating from 5 MW to 4.5 MW, which in turn reduces the effective load from 4.5 MW to 3.02 MW. The corresponding aggregate load to be served from the Swing Bus is reduced from the original 6 MW down to 5.69 MW.

### *Approach to Assessing Locational Aspects of DG*

A forecast on potential SGIP locations, generator type, and generating capacity was modeled in the power flow simulations to determine the potential for DG facilities to provide positive benefits to the transmission grid at strategic locations.

The methodology for evaluating the transmission benefits of DG facilities located at different locations is termed the Aggregated MegaWatt Contingency Overload (AMWCO). Power flow simulations were completed under first contingency (N-1) conditions for each scenario for the summer peak hour. One at a time, each power flow element (e.g., a transmission line, transformer, or generator) was temporarily removed from service and a power flow simulation was completed. This process was repeated for each element in the power flow case. One or more of these individual simulations may cause an overload on one or more elements. The percent overload of the element was weighted by the number of outage occurrences and the percent overload. The summation of the weighted overloads was the AMWCO. The difference between the AMWCO for the base case and each DG facility case divided by the capacity of the installed DG represents the Distributed Generation Transmission Benefit Ratio (DGTBR). AMWCO is a transmission reliability index with a unit of measure in MW. As a result, the DGTBR is the improvement in the reliability index per MW of installed DG. For the cases with and without the DG modeled, the AMWCO is calculated. The difference between the two AMWCO values divided by the DG capacity determines the DGTBR. A negative DGTBR represents an improvement in system reliability. A positive DGTBR indicates a probable decrease in system reliability. This approach is based on a similar approach used for assessing transmission impacts due to integration of renewable energy facilities.[19]

[19] California Energy Commission, *Strategic Value Analysis for Integrating Renewable Technologies in Meeting Renewable Penetration Targets*, CEC-500-2005-106, June 2005.

# 3

# Study Results

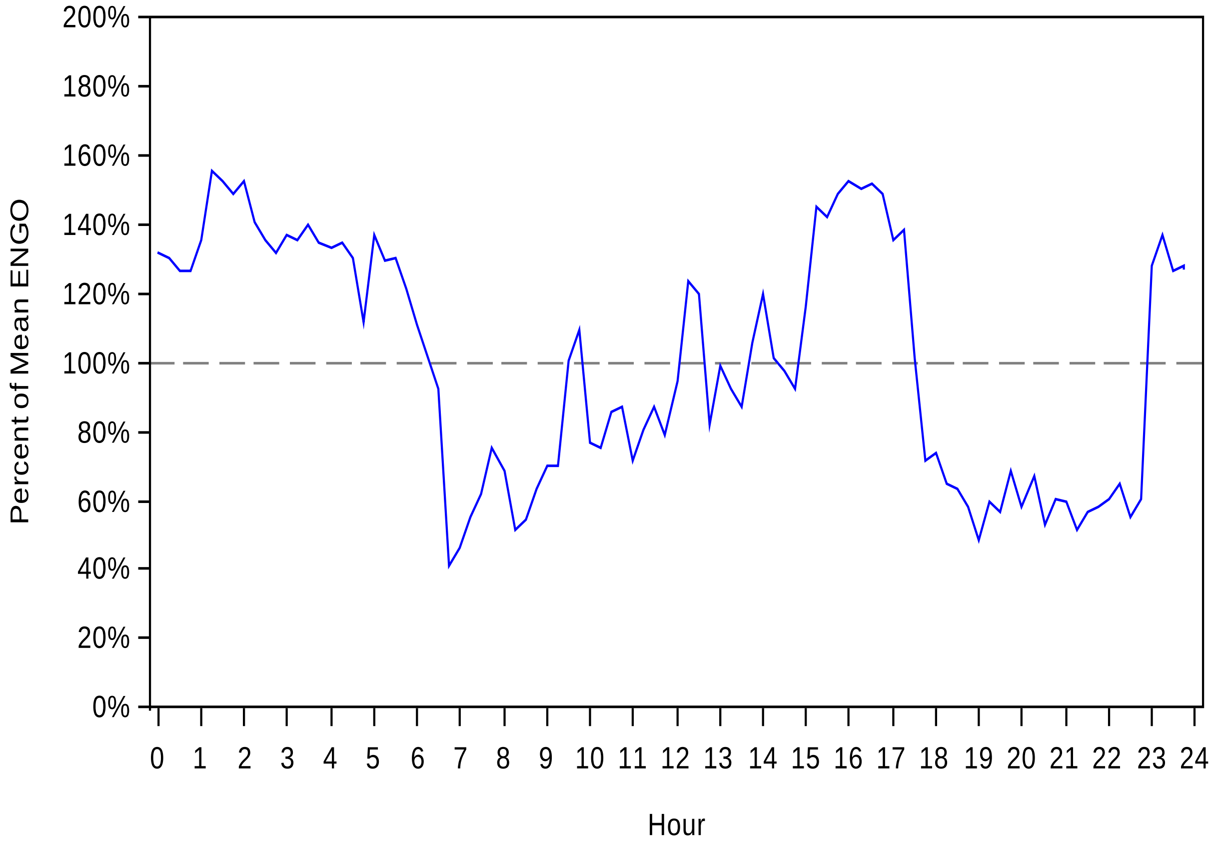
## 3.1 Representative DG Generation Profiles

Metered generation data from DG systems deployed under the SGIP form the basis for assessing the dispatch capabilities of DG systems. Each DG system operates on conditions specific to the host site, local geography, and climate. Consequently, to translate results to a broader group of conditions, it was necessary to develop "representative" generation profiles. We used metered electricity generation output (termed Net Electricity Generator Output or ENGO) data to classify the DG profile as either "baseload" or "non-baseload." Baseload implied a relatively consistent level of output whereas non-baseload was indicative of much more volatility in the hourly output. Our premise is that non-baseload sites will have more variation in their generation patterns as the output of a unit goes up and down to follow the site's demand. This volatility can be measured in the raw data and used to classify generator profiles.

We explored a number of different ways for measuring volatility, including the use of different ratios of minimum, maximum, and mean generation values over different time-periods. Many of these worked well for some cases but were not consistent enough to apply as a general measure of generation volatility. For this analysis, the most stable metric for generation volatility was the percent deviation of each ENGO observation from the mean of non-zero ENGO values over the day. The exclusion of zero ENGO values was necessary because some units frequently shut down for extended periods during the day. This shutdown of a generator dramatically lowers the average output and reflects variability that was rarely due to an attempt to ramp up to site demand. The comparison to the daily average ENGO as opposed to the overall average ENGO was necessary because many sites have generation that is clearly level on most days, but which operate at substantially different capacity factors.

Figure 3-1 is an example of volatile generation for a single day. As Figure 3-1 shows, the ENGO values go up and down frequently throughout the day, with individual observations ranging from 40% to 160% of the mean.

**Figure 3-1: Example of a Volatile Generation Day—ENGO as Percent of Average ENGO**



In contrast, Figure 3-2 shows ENGO output that operates at fairly steady levels. As shown, with the exception of one mid-morning drop to 40% of the mean, the levels of output do not deviate much at any other time of the day.

**Figure 3-2: Example of a Non-Volatile Load Day—ENGO as Percent of Average ENGO**

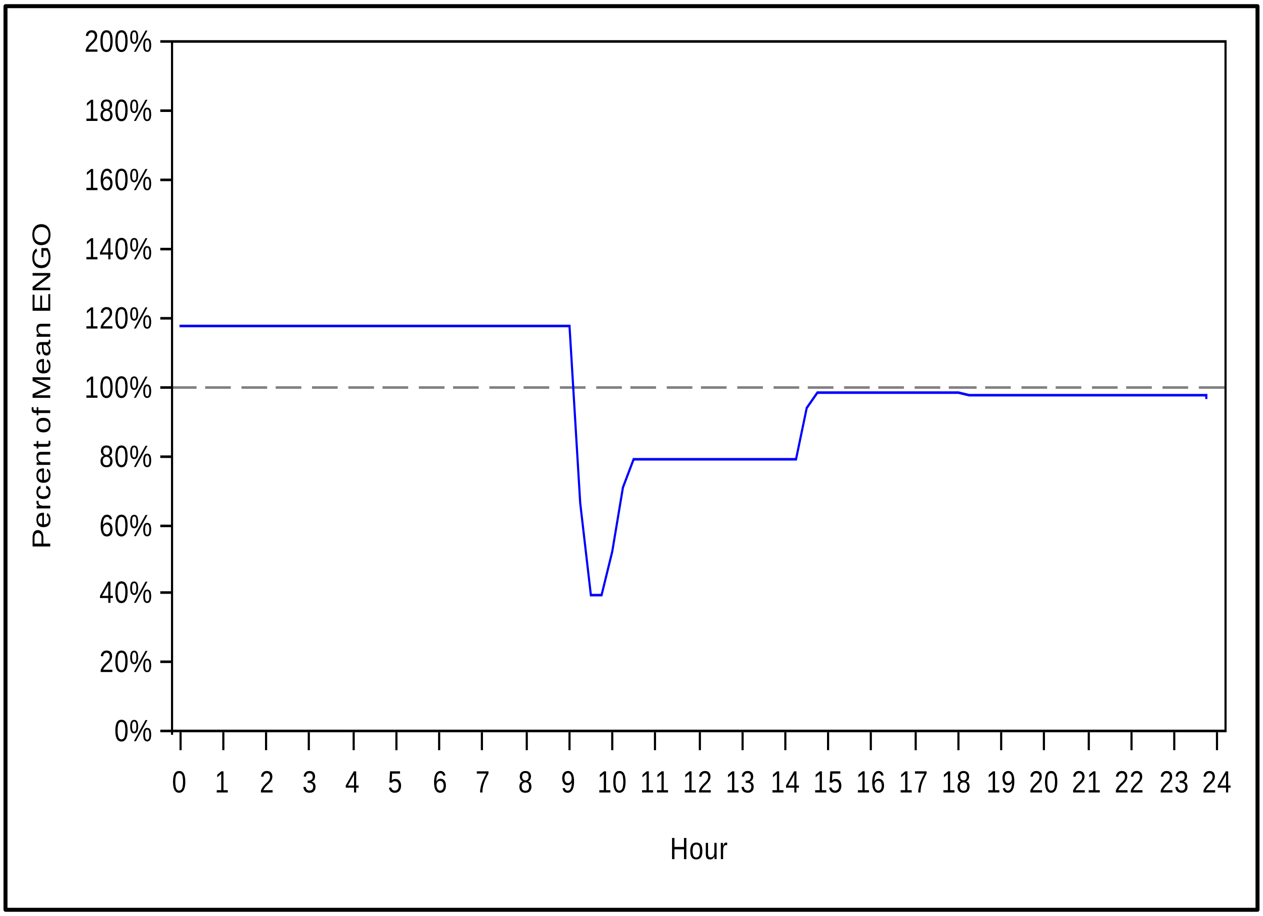


Figure 3-1 and Figure 3-2 show volatility over just one day. However, it is important to characterize volatility over a longer time to develop representative generation profiles that can be used throughout the summer months or year. Figure 3-3 and Figure 3-4 show the loads for the same sites for the entire month of June 2008. Figure 3-3 shows that the volatility seen in the single day is even more evident in the wider range of days, with some observations approaching 200% of the daily average. In Figure 3-4, the lack of volatility is also abundantly clear, with a clustering of days that show almost no deviation from the mean output. Note there are many days where the load drops to zero. These observations are excluded from the calculation of the mean because they would show changes in load that likely have nothing to do with a unit's attempt to meet site demand.

**Figure 3-3: Example of a Volatile Load, All June Days—ENGO as Percent of Average ENGO**

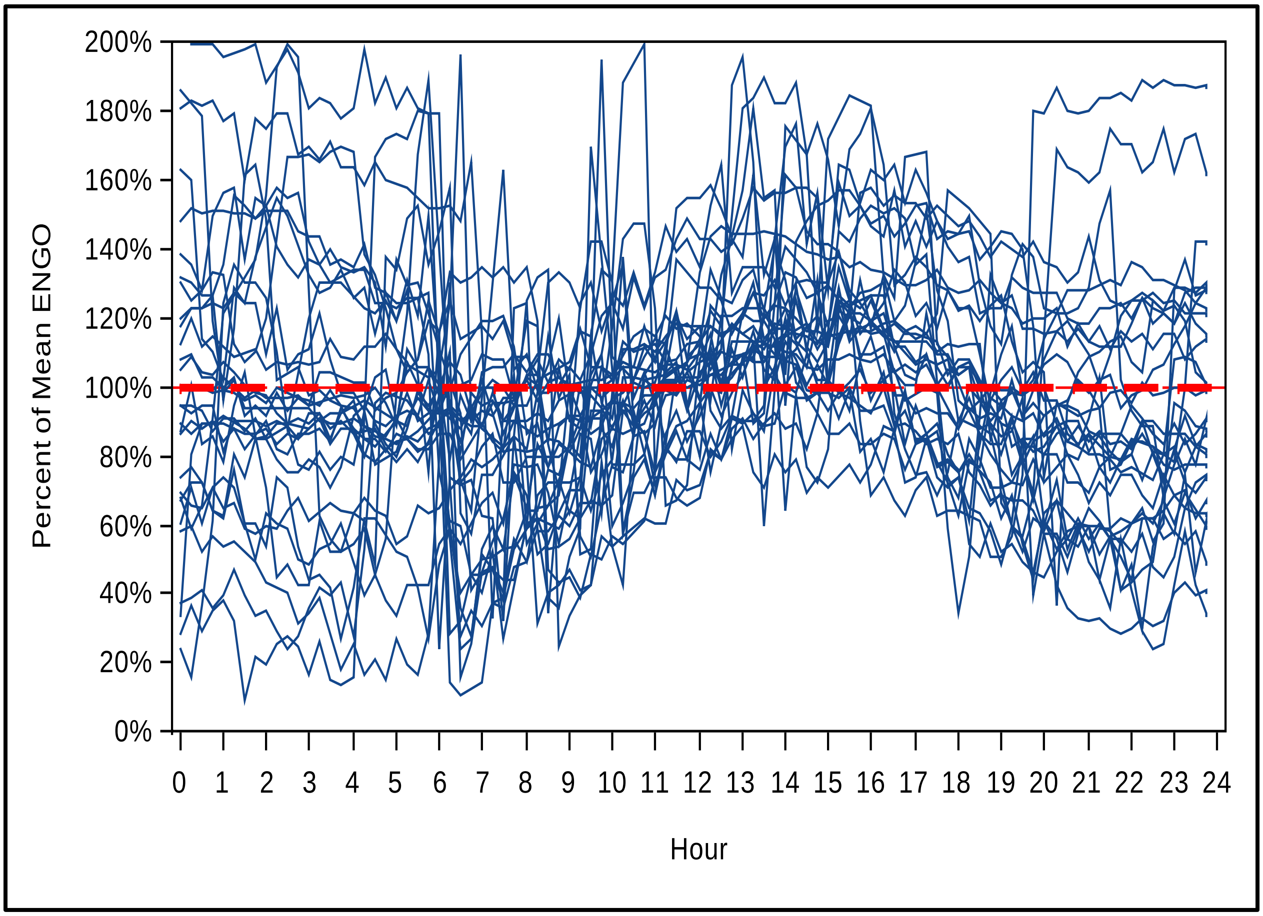
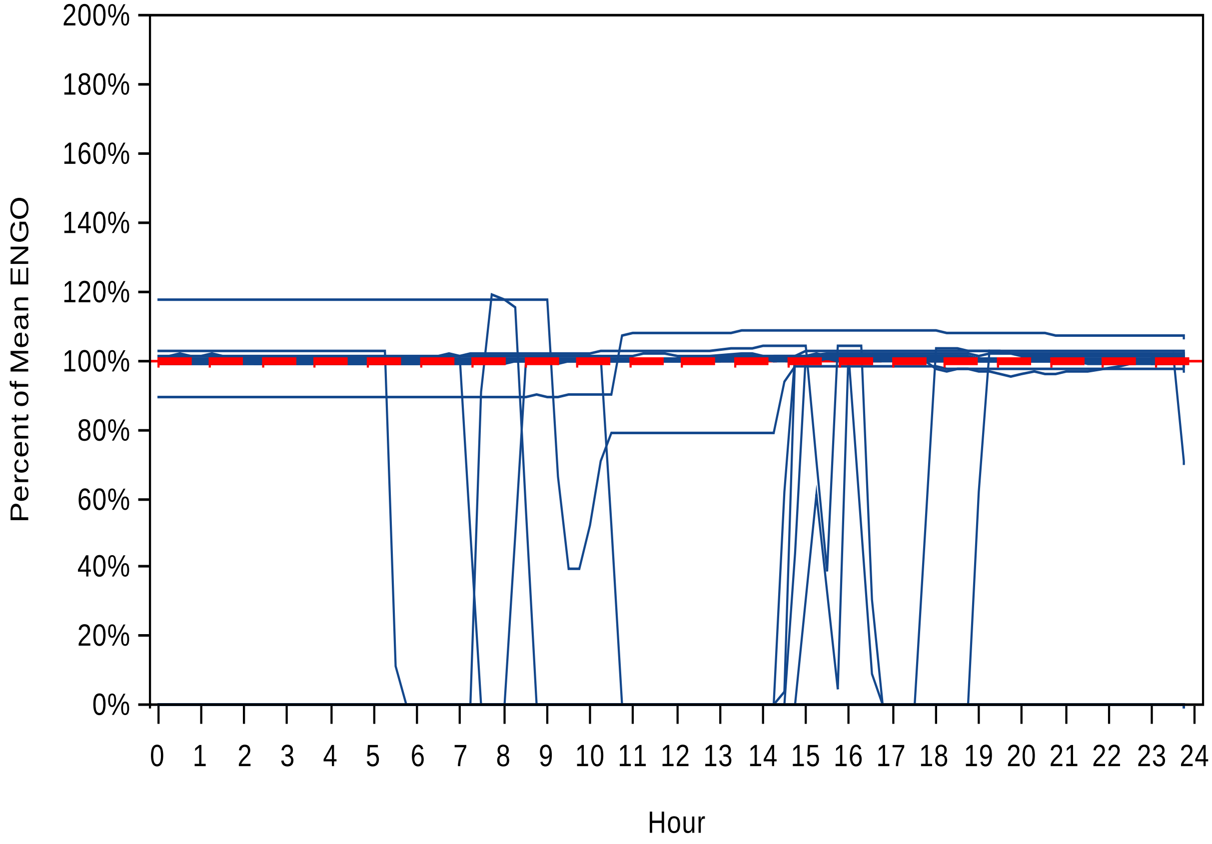


**Figure 3-4: Example of a Non-Volatile Load, All June Days—ENGO as Percent of Average ENGO**



We reviewed generator profiles for 198 SGIP sites. After a review of the generator profiles, we elected to classify generation based on 20% or greater deviations from the mean occurring at least 20% of the time. Using these criteria, the final counts for the classified generator profiles by technology, location, and type of site are shown in Table 3-1. Note that of the original 196 sites examined, the analysis excluded 46 that had exclusively zero values for the four summer months.[1] There were no sites with fuel cells or gas turbines classified as non-baseload using these criteria and, overall, 89% of the sites were classified as baseload.

**Table 3-1: Counts of Final Load Profiles Classified by Technology**

| | | | **Load Profile** | | |
|---|---|---|---|---|---|
| **Technology** | **Location** | **Site Type** | **Baseload** | **Non-Baseload** | **Total** |
| Fuel Cell | Coastal | Occupancy | 7 | 0 | 7 |
| | | Process | 1 | 0 | 1 |
| | Inland | Occupancy | 3 | 0 | 3 |
| | | Process | 4 | 0 | 4 |
| | | *Total* | *15* | *0* | *15* |
| Gas Turbines | Coastal | Process | 3 | 0 | 3 |
| | Inland | Occupancy | 1 | 0 | 1 |
| | | Process | 1 | 0 | 1 |
| | | *Total* | *5* | *0* | *5* |
| IC Engine | Coastal | Occupancy | 22 | 4 | 26 |
| | | Process | 8 | 2 | 10 |
| | Inland | Occupancy | 22 | 1 | 23 |
| | | Process | 12 | 5 | 17 |
| | | *Total* | *64* | *12* | *76* |
| Microturbine | Coastal | Occupancy | 17 | 2 | 19 |
| | | Process | 10 | 1 | 11 |
| | Inland | Occupancy | 15 | 1 | 16 |
| | | Process | 6 | 1 | 7 |
| | | *Total* | *48* | *5* | *53* |
| | | **Grand Total** | **132** | **17** | **149** |

[1] It would require additional research to know the actual reason why these sites had no generation during the summer months. However, there are many possible reasons, including systems that have reached the end their useful life, absence of a qualified operator, financial reasons, or facilities that are commissioned.

As an indicator of the robustness of these classifications, Table 3-2 shows the percentage of individual days classified consistently with the final generator profile. With the exception of fuel cells, the sites classified as baseload all had a more than 90% of their individual days classified consistently. For the sites classified as non-baseload, the share of individual days classified in a consistent manner was not as high, but the results still show that most sites fit clearly into one of the two profile types when using the 20% deviation occurring 20% of the time criteria.

**Table 3-2: Mean Percent of Days Classified by Technology**

| | Classified Generation Profile | |
|---|---|---|
| **Technology** | **Baseload** | **Non-Baseload** |
| Fuel Cell | 88.4% | NA |
| Gas Turbines | 97.7% | NA |
| IC Engine | 92.8% | 72.7% |
| Microturbine | 95.1% | 86.2% |

We also grouped generators by location (inland or coastal) and by type of commercial application (i.e., occupancy versus process). Generators were grouped by location to take into account the impacts of weather dependent load on those generators that were non-baseload. In particular, SGIP sites located in hot inland areas could be expected to show greater loads in the afternoon due to increasing air conditioning loads due to higher ambient temperatures. Similarly, host sites of generators were grouped into two general classifications of commercial application: occupancy-oriented versus process-oriented. In general, occupancy-oriented applications were those deemed to have electricity loads primarily driven by occupancy activities. For example, business offices, schools, and hotels were deemed to have electricity demand largely driven by HVAC loads, lighting, etc. Conversely, process-oriented applications were deemed to be those largely driven by industrial or commercial processes, such as manufacturing of processing of materials. We used NAICS codes in conjunction with site inspection data to determine the type of business of the host site.[2] Based on this information, we then grouped SGIP sites into occupancy versus process-oriented classifications.

---

[2] The occupancy- and process-based site categories were created primarily from two-digit NAICS codes. NAICS codes in the 30s and lower (e.g. Mining, Utilities) were categorized as process-based. NAICS codes in the 40s and higher (e.g., Health Care and Social Assistance, Accommodation and Food Services) were categorized as occupancy-based sites. For a few cases with missing data or ambiguous NAICS descriptions, the categorization was based on the site or company name.

A comparison of the baseload and non-baseload profiles is presented in a series of plots below. Figure 3-5 and Figure 3-6 show the baseload and non-baseload generation profiles for coastal and inland locations, respectively. Figure 3-7 and Figure 3-8 show the generation profiles for process- and occupancy-based sites. The figures present the generation profiles in terms of mean capacity factors to put them on an equivalent scale with vertical ticks showing the 99% confidence limits. The important aspects of these graphs are the shape and the variability in capacity factors associated with type of generation profile. Any comparison of the magnitude of the capacity factors has two key caveats. First, the generation profiles are comprised of sites with different technologies that may have different operating characteristics. Consequently, differences in capacity factors could be driven by the characteristics of the sites. Second, the number of sites included in each mean generation profile varies considerably, with some of the non-baseload profiles consisting of only a few sites. For example, with the occupancy-based sites in Figure 3-8 (the non-baseload profile) is based on eight sites, while the baseload profile has data from 87 sites.

In general, non-baseload generation profiles shown in Figure 3-5, Figure 3-6, Figure 3-7, and Figure 3-8 exhibit two characteristics that distinguish them from the baseload generation profiles. First, they show a clear rise during daytime hours. This daytime hour rise is likely associated with the increase in DG output to meet a site's increased demand due to occupancy- and weather-related factors. This is particularly clear in Figure 3-5, which shows the mean capacity factors for coastal locations, and Figure 3-8 which shows the mean capacity factors for occupancy-based sites. Second, the non-baseload generation profiles show more variability in their mean hourly capacity factors, as seen in the vertical ticks that represent the 99% confidence intervals. This is clearly visible in all four figures, where the baseload generation profiles have much narrower bands around the mean capacity factor values.

**Figure 3-5: Average Capacity Factors for Baseload and Non-Baseload, Coastal**

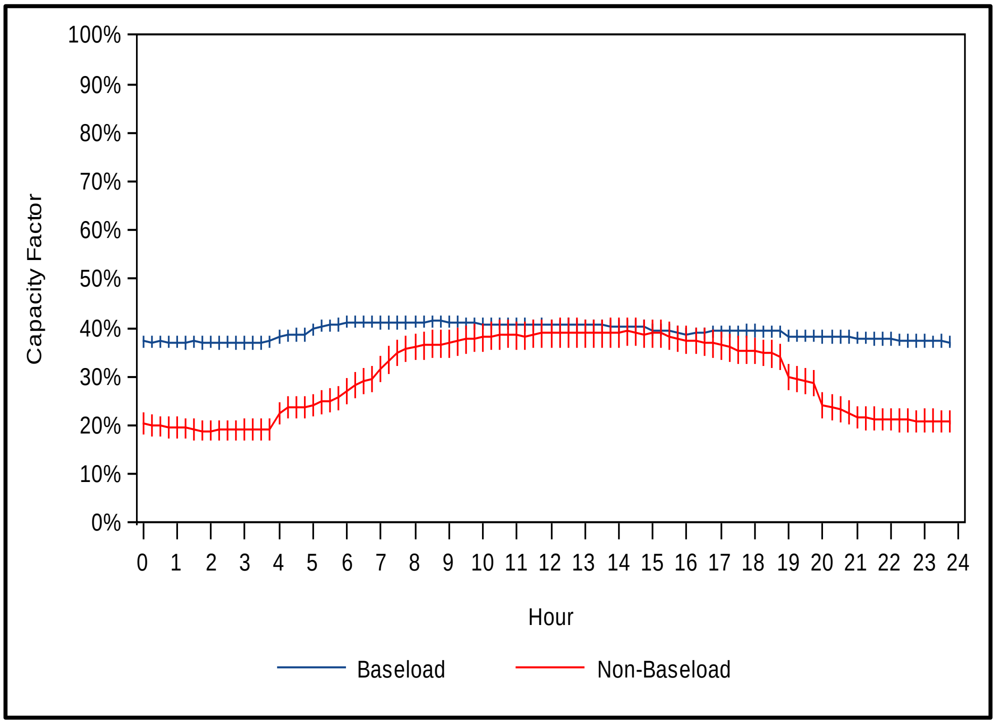



**Figure 3-6: Average Capacity Factors for Baseload and Non-Baseload, Inland**

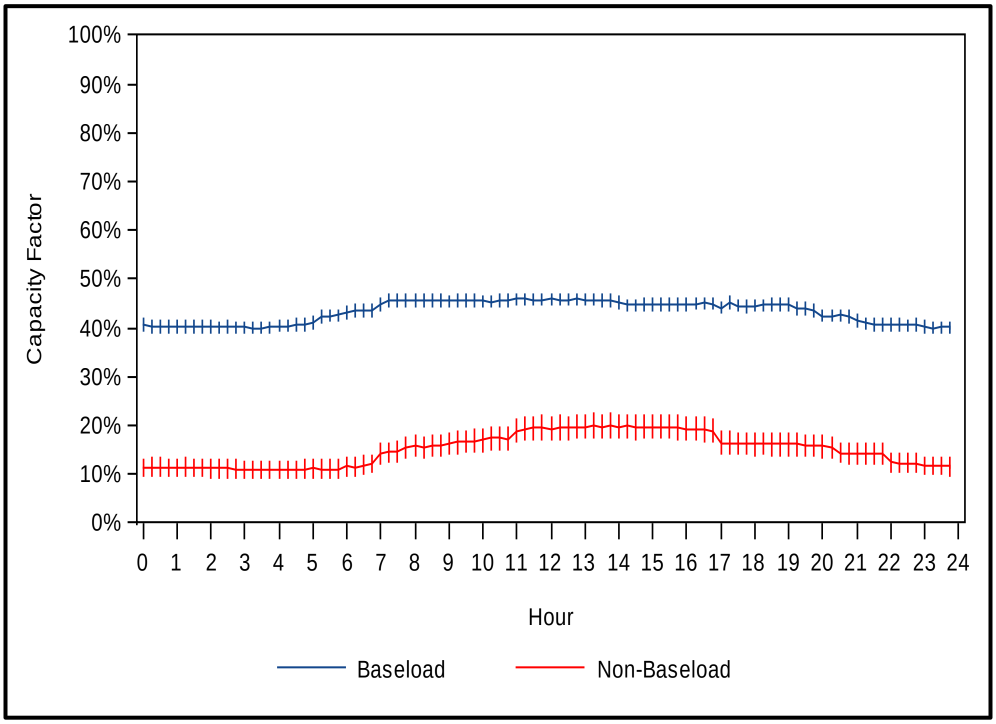


**Figure 3-7: Average Capacity Factors for Baseload and Non-Baseload, Process Sites**

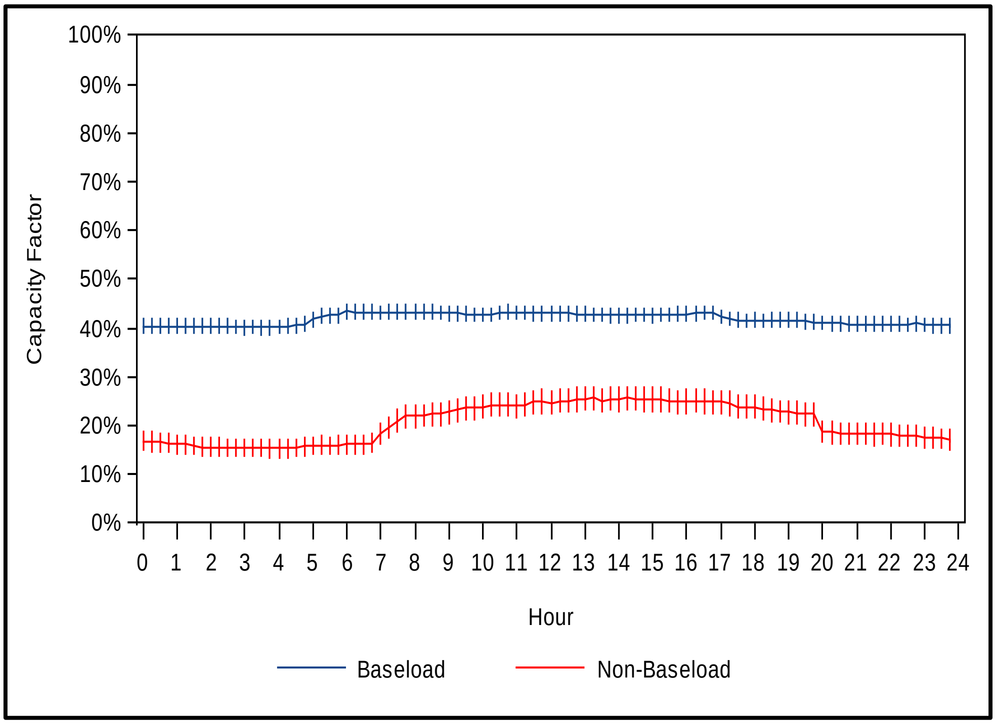
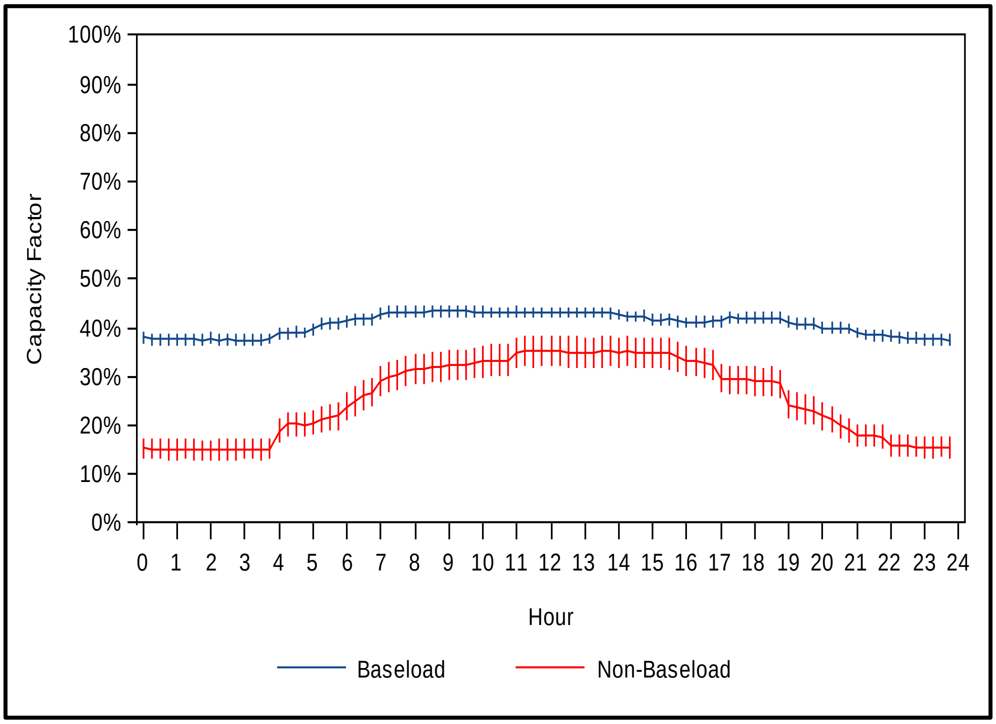



**Figure 3-8: Average Capacity Factors for Baseload and Non-Baseload, Occupancy Sites**



### *Observations on Representative DG Generation Profiles*

We used metered electricity data from DG systems deployed under the SGIP and operating during the summer of 2008 as the basis for establishing representative DG generation profiles. At the end of 2008, there were approximately 1,275 DG systems operational in the SGIP, of which 391 were combined heat and power facilities. Generation profiles for 149 of these systems (or approximately 38% of all CHP facilities) were examined and classified as baseload or non-baseload. Based on our analysis, we found:

- *DG systems deployed under the SGIP can be successfully classified into baseload and non-baseload generation characterizations by type of DG technology, location, and application.*
- *The vast majority (nearly 89%) of the DG systems examined fell into the baseload characterization, while the remaining 21% of DG systems can be characterized as non-baseload generators.*
- *Fuel cells and gas turbines show clear classification as baseload generators, whereas IC engines and microturbines show generation profiles that can be characterized as either baseload or non-baseload.*

## 3.2 Representative SGIP Facility Demand Profiles

In developing generation profiles, we deliberately chose to use baseload and non-baseload designations rather than baseload and "load-following" designations. In particular, the non-baseload generation profiles were assumed to act as proxies for load-following generators. In order to examine the accuracy of this assumption, we asked the IOUs to supply us with SGIP site demand data for those sites for which we had ENGO data. By comparing generator profiles against site demand data, we could determine the extent to which a generator was following load. In addition to the ENGO data used for generation load profiles, one utility (PG&E) provided site-level demand data for a subset of sites. Table 3-3 provides a count of sites by the location, site type, and the classified generation profile for which we also had site demand data.

**Table 3-3: Count of Sites with Demand Data**

| | | Generation Load Profile | | |
|---|---|---|---|---|
| **Location** | **Site Type** | **Baseload** | **Non-Baseload** | **Total** |
| Coastal | Occupancy | 5 | 2 | 7 |
| | Process | 1 | NA | 1 |
| Inland | Occupancy | 3 | NA | 3 |
| | Process | 3 | NA | 3 |
| Total | Total | 12 | 2 | 14 |

Although the demand data represent a small number of sites, they still merit examination for several reasons. First, they allow for an examination of demand profiles at the individual site level. Second, they can be summarized to develop mean demand profiles at varying levels of aggregation. Third, they can be combined with the ENGO data to how DG is used to meet overall site demand needs. This final use of the data also serves to validate the results of the demand profile classification analysis.

### *Mean Demand Profiles*

One caveat with this analysis is that the total demand values have been calculated as the sum of the provided demand data and the generation data. While the data provided by PG&E were not explicitly documented as being net of generation demand, a visual review of the data during the initial diagnostics conclusively demonstrated that the PG&E data were the metered demand, not the total site demand. For example, Figure 3-9 shows the daily demand profiles along with the overall average for the metered demand data provided by PG&E. The average demand profile shows a small spike in the morning as demand starts to grow; then it drops back down and remains relatively flat until the evening hours, when there is a substantial dip in demand. This load profile is already highly unlikely, but when compared to the profile shown in Figure 3-10—when the generation data are added to the metered demand to create the total demand—it becomes clear that the original data did not include generation. There were enough compelling examples for nearly every site that the generation was added to create the total demand in all cases.

**Figure 3-9: Plot of Metered Demand, All Days with Mean**

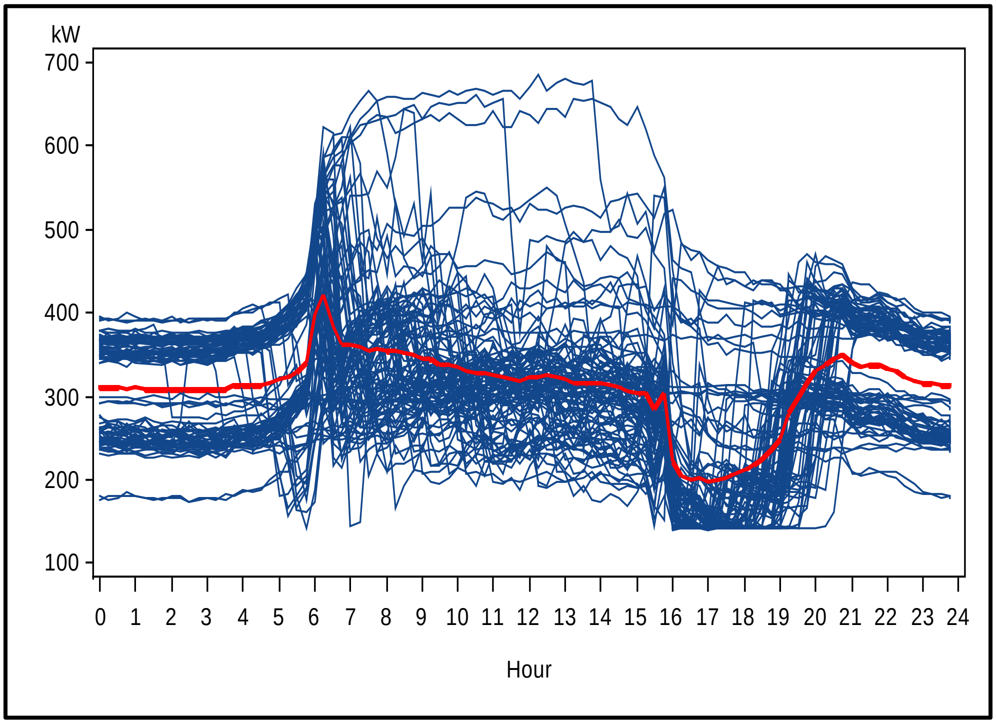
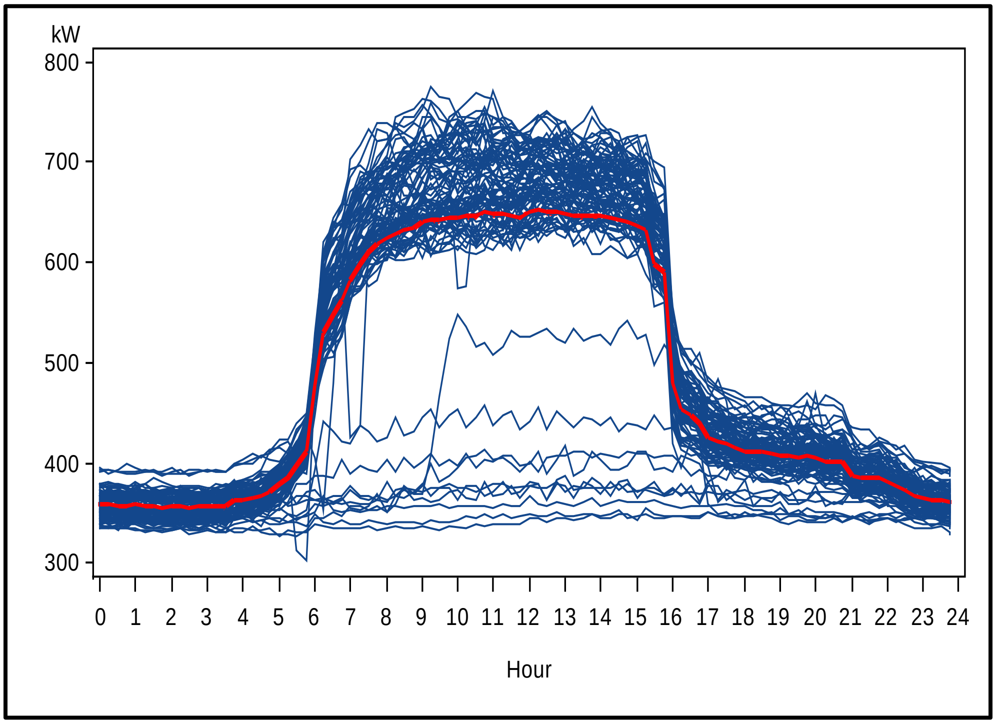



**Figure 3-10: Plot of Total Demand, All Days with Mean**



As with the generation profiles, the data can be used to calculate mean demand profiles at different levels of aggregation. For example, Figure 3-11 and Figure 3-12 show the mean demand profiles for coastal and inland locations and occupancy- and process-based sites, respectively. The figures are presented as the percentage of maximum demand to make the profiles more directly comparable, with the 99% confidence limits presented as vertical ticks. These demand profiles are limited in their applicability due to the sample size. For example, the demand profile for coastal locations in Figure 3-11 consists of sites that are occupancy-based sites for all but one location, so the shape likely has less to do with the location than facility characteristics. The demand profiles in Figure 3-12 are more intuitive, with the process-based sites showing the more variable demand likely associated with operation schedules.

**Figure 3-11: Mean Demand Profiles for Coastal and Inland Locations**

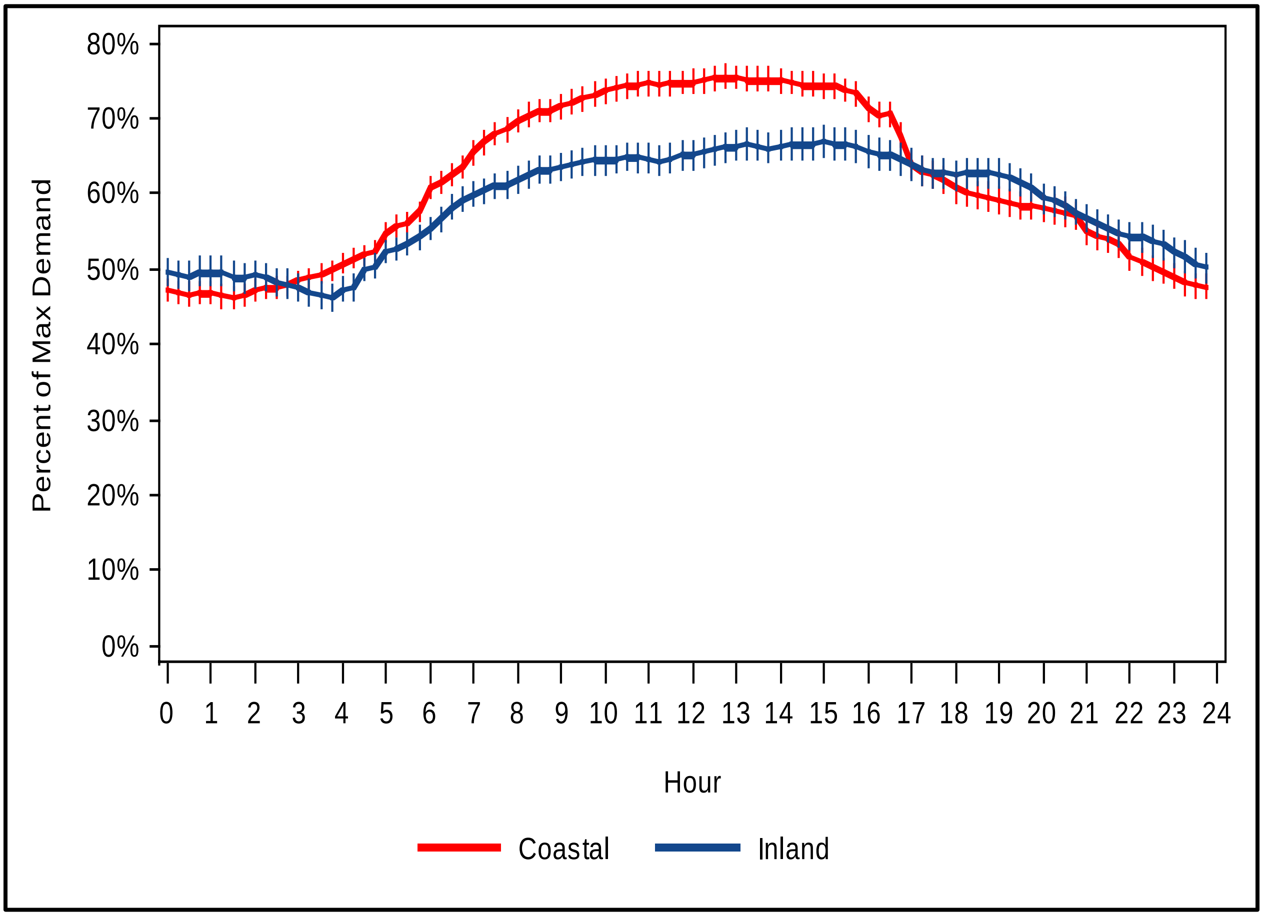
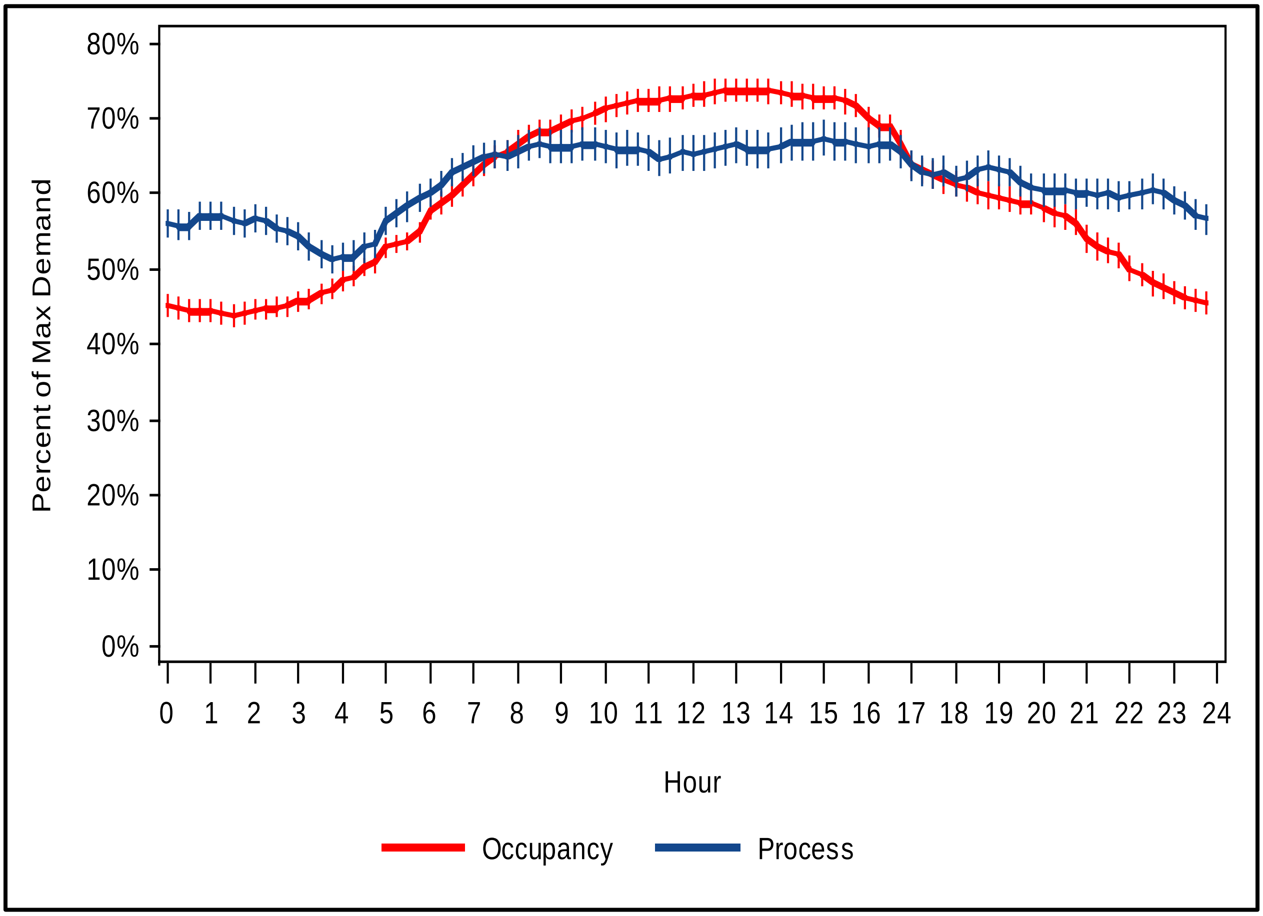


**Figure 3-12: Mean Demand Profiles for Occupancy- and Process-Based Sites**



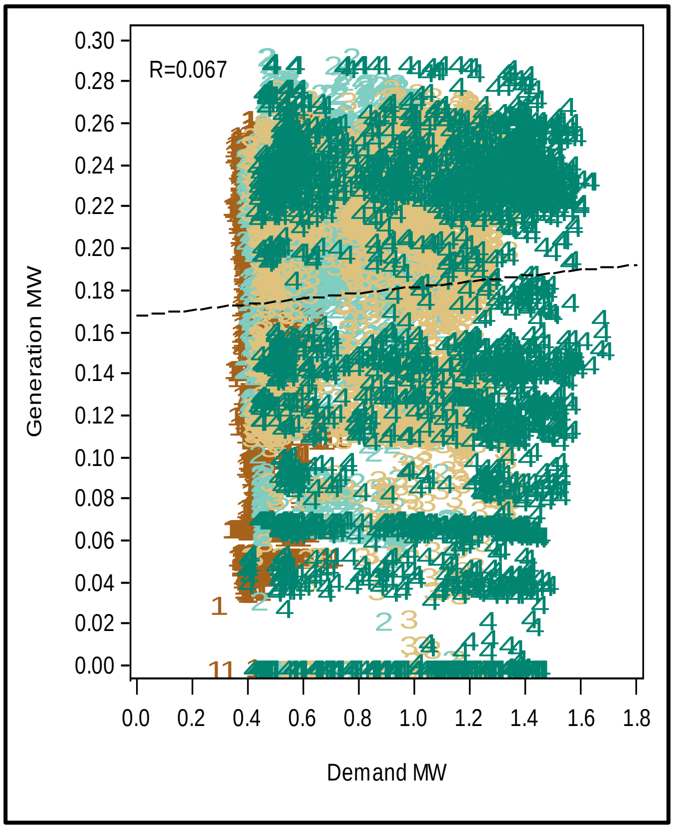

### *Generation with Total Site Demand*

The availability of demand and generation data offers an opportunity to look at the relationship between the DG system and overall site demand. These data can show the overall contribution of DG to meeting site demand and also how different technologies are used during times of peak demand.

The site demand data allow for an alternative means of classifying whether a site's generation is baseload or non-baseload. An examination of the correlation between generation and total demand offers an empirical means of determining whether a DG technology classified as non-baseload is acting as a load-following generator.

Figure 3-13 presents a plot of generation by demand for a selected site, with generation plotted as the dependent variable because increasing use of energy is what would cause a site to increase its DG output. The symbols in the plot are numbers one through four, which represent the quartiles for daily maximum demand (four equals the top 25% of daily peaks).

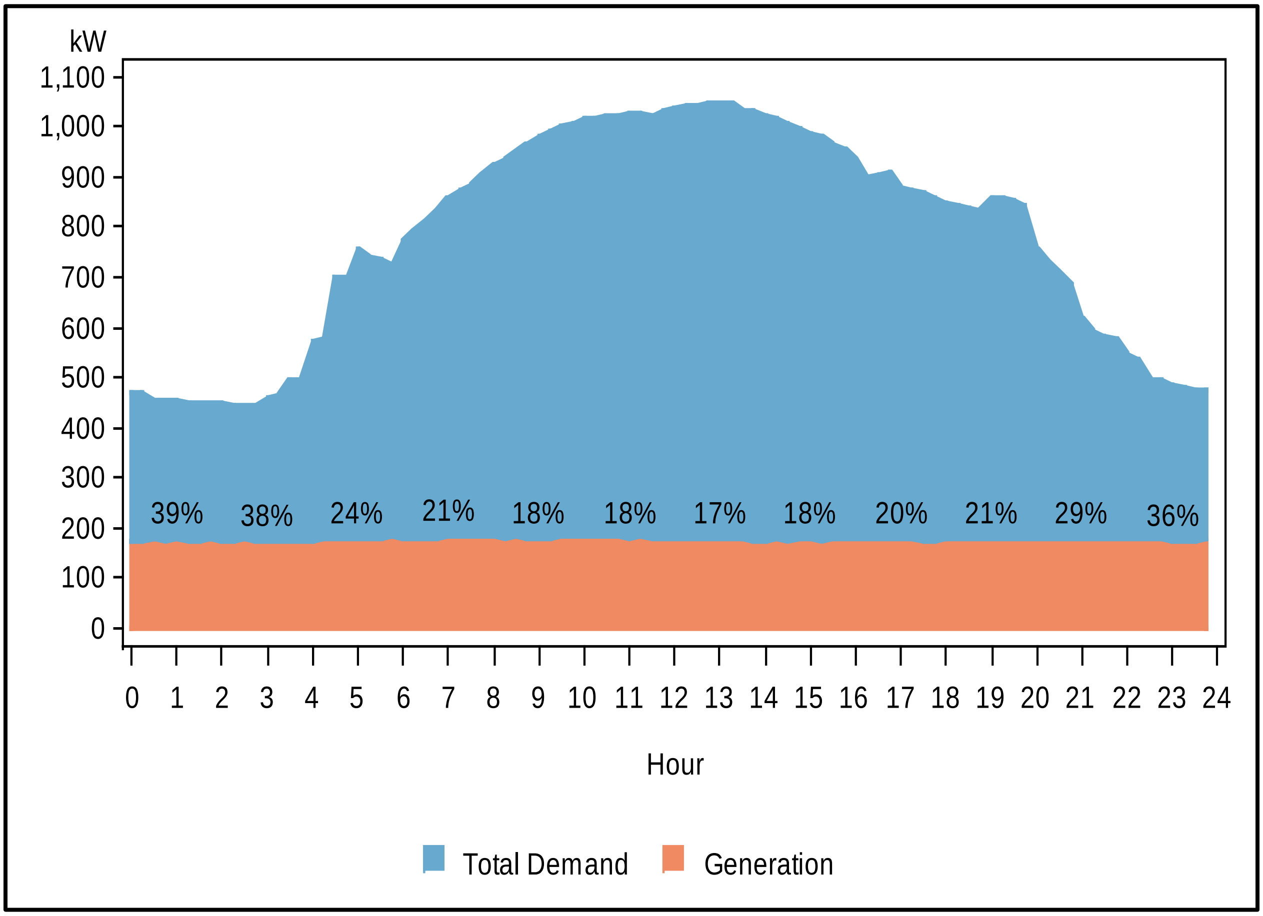
**Figure 3-13: Scatter of Generation and Demand by Maximum Demand Day Quartiles, Low Correlation**




This representation of the data allows us to determine whether there is a different relationship on days when demand at the site is higher or lower. As additional detail, the correlation is provided in the upper right and the line associated with the linear regression equation is imposed over the data points. The correlation associated with these data is 0.067, which means there is a weak relationship between generation and demand. The data points lie in a rectangular shape, with no pattern showing increased generation with higher levels of site demand. The demand quartiles show no particular pattern beyond the normal dispersal that one would expect to see. As a visual demonstration of the low correlation, the regression line lies almost flat.

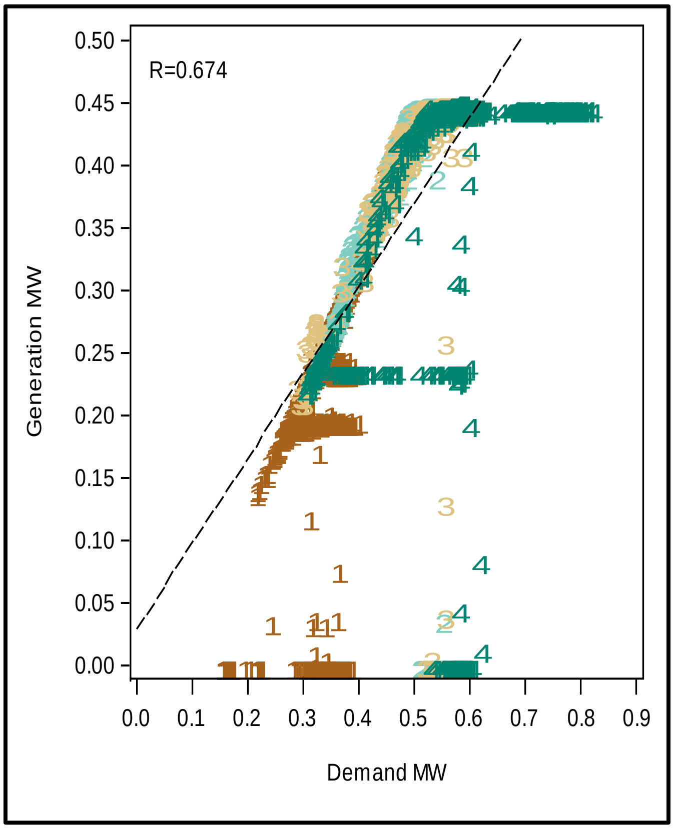
As an alternative illustration of the lack of relationship between generation and demand, Figure 3-14 shows the average hourly values for these variables. The percentage of total demand met by generation, which annotated for odd hours, declines as the demand increases and the DG output remains fairly constant, which provides further evidence that the site represents a baseload profile.

**Figure 3-14: Average Hourly Generation and Total Demand, Low Correlation**



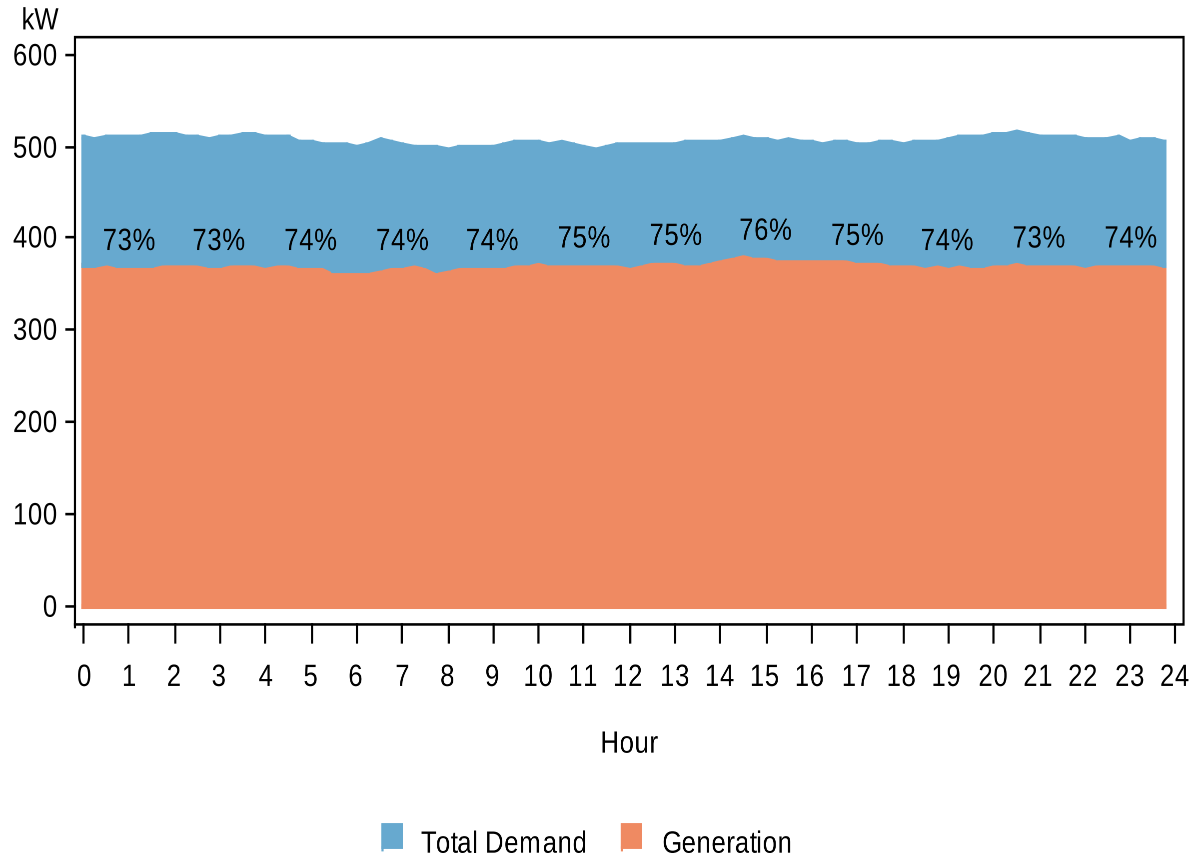

In contrast to the example presented above, two cases are presented below for sites where demand and generation do exhibit a strong relationship. Figure 3-15 and Figure 3-16 present a scatter plot of generation and demand and the hourly mean values, respectively, for the first high correlation case. The data in Figure 3-15 represent a correlation of .674 and the generation shows a nearly linear increase as demand goes up until it flattens out at around .44 MW, likely when the DG unit has reached its capacity. The symbols for quartiles associated with peak demand days are also separated into fairly discrete groups on the plot, showing that the DG unit is rarely operated at a high capacity unless overall demand at the site requires it.

**Figure 3-15: Scatter of Generation and Demand by Maximum Demand Day Quartiles, High Correlation (Case One)**




While the relationship between generation and demand is clear in Figure 3-15, in Figure 3-16 there is no evidence to suggest that the DG unit operates at a higher level to meet facility needs. This is in large part because the demand profile at the site is very flat on average, with no significant hourly variation. Likewise, the generation profile is also flat, meeting a nearly constant three quarters of the overall site demand. One must refer back to Figure 3-15, which shows that the daily maximum demand values are significantly distributed, to be sure both the generation and demand profiles are not at nearly constant levels on all days.

**Figure 3-16: Average Hourly Generation and Total Demand, High Correlation, (Case One)**




The second case of a site with a strong relationship between generation and demand is presented in Figure 3-17 and Figure 3-18. The correlation of 0.815 is the strongest of the three examples presented, with the data points in Figure 3-17 clearly showing the increase in generation as demand rises. There are many more data points at or near zero generation compared to the first, showing that this unit has more of an on and off operation schedule. The hourly average profiles shown in Figure 3-18 add more support for the non-baseload classification of the generation profile. In stark contrast to Figure 3-14, the contribution of generation to meeting total demand actually goes up during the hours when demand increases, meeting more than 50% of the site's needs during the peak afternoon hours.

**Figure 3-17: Scatter of Generation and Demand by Maximum Demand Day Quartiles, High Correlation (Case Two)**

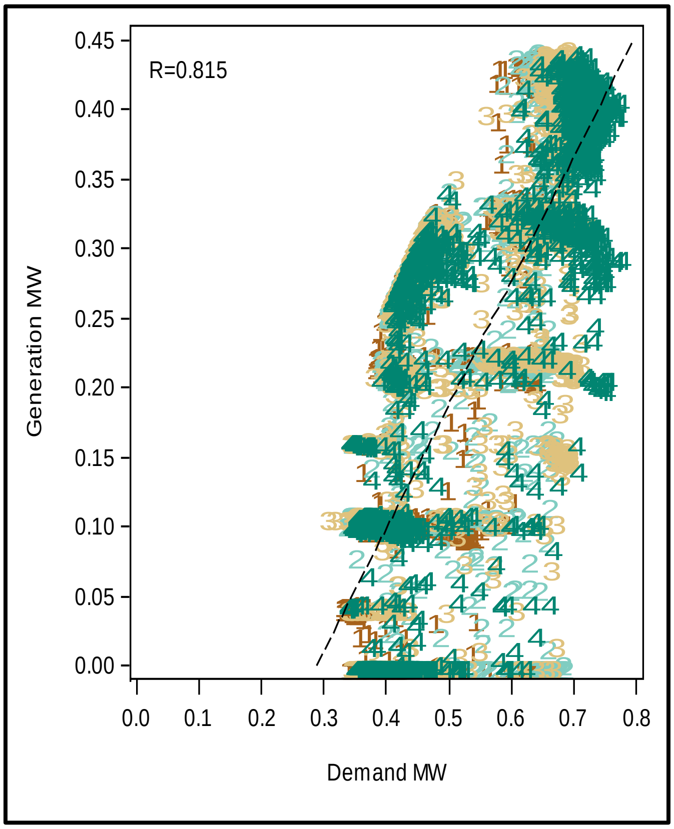
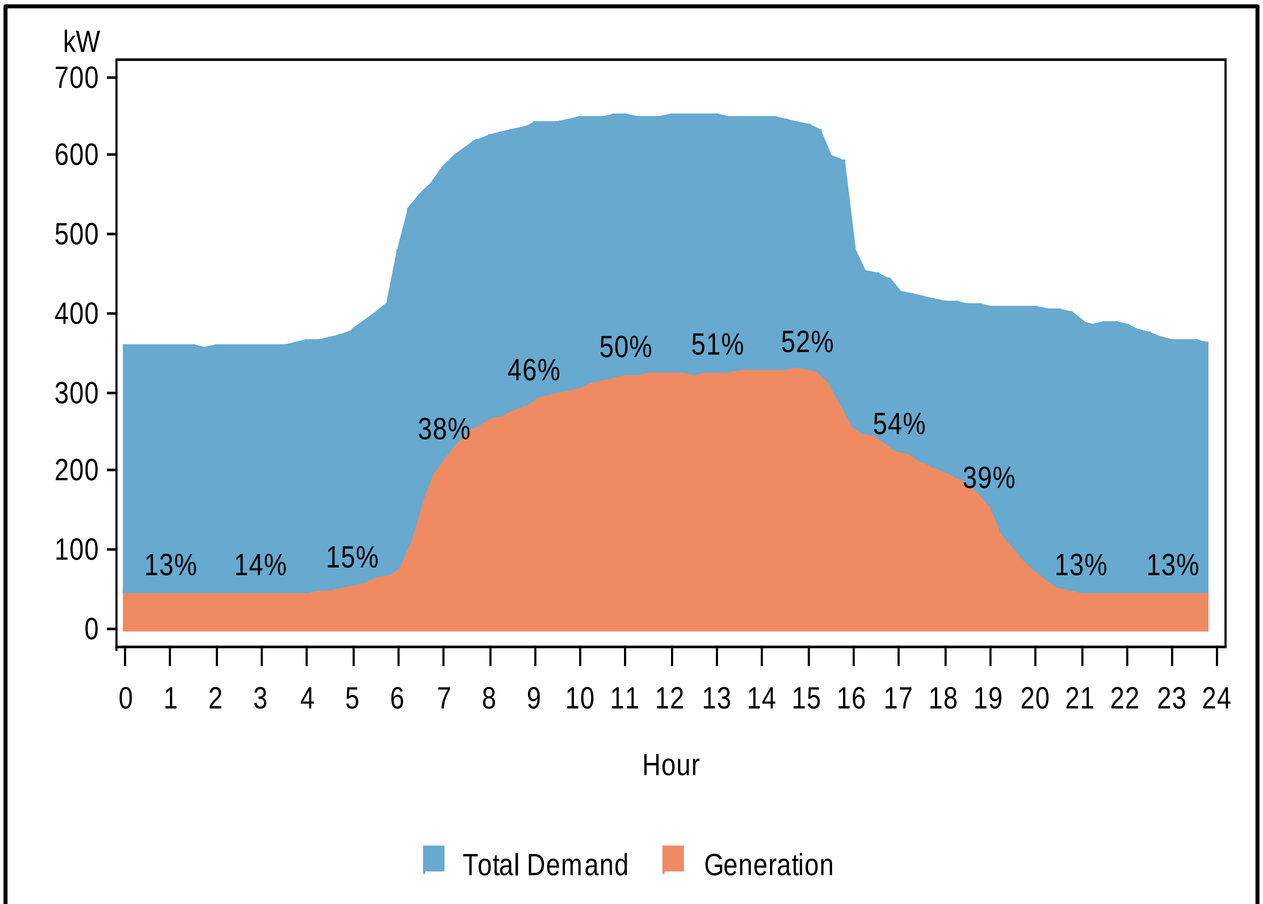


**Figure 3-18: Average Hourly Generation and Total Demand, High Correlation (Case Two)**




### *Observations on Representative Site Demand Profiles*

Unlike DG generation profiles, we had a limited amount of site demand data for SGIP facilities housing DG systems. While the provided data was restricted to a single IOU service territory, it is probably reasonable to assume that site demand data for the one utility is representative of site demand data for other California utilities. In particular, we expect electricity demand at facilities to be more dependent on location (i.e., inland versus coastal) and application (i.e., occupancy-driven versus process-driven) than on IOU service territory. With these caveats in mind, we have the following observations:

- *We are able to successfully classify the sites for which we have site demand data as showing demand profiles that fall into either being baseload or non-baseload categories.*
- *Like the generator profile data, the site demand data showed that most of the examined sites had baseload type demand shapes. However, due to the very small sample size, there is little statistical basis upon which to extend this to the SGIP in general.*

- *By comparing generation profile data against site demand data, we are able to determine if a generator is acting as a load-following generator. However, due to the small sample size of site demand data, we are not able to determine how many of the DG systems classified as non-baseload generators are actually acting in a load-following pattern.*

## 3.3 Improving Dispatch of DG Resources

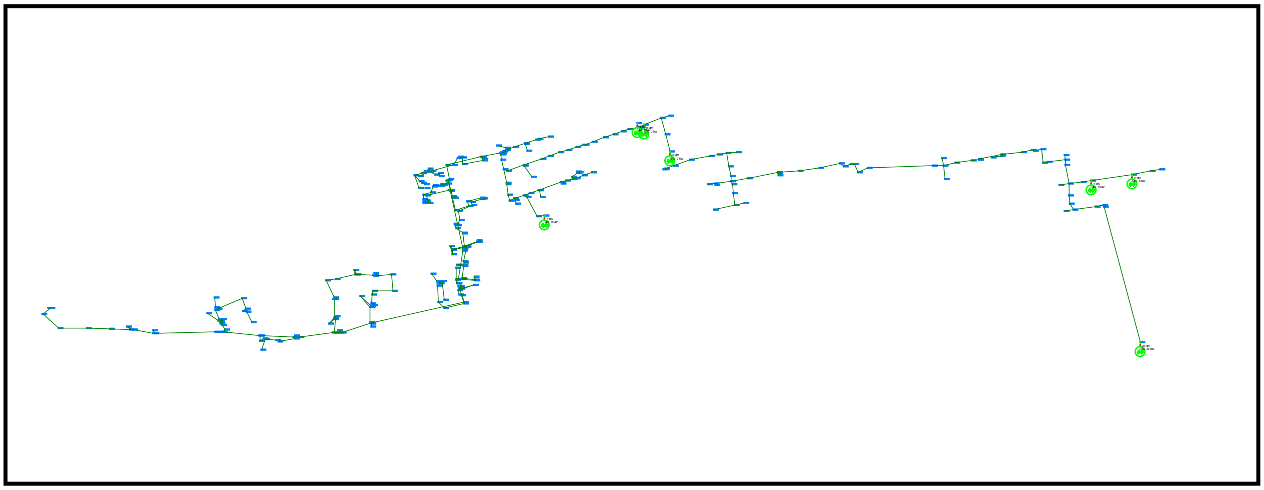
Section 3.1 showed representative generation profiles for different types of DG systems located in various locations (i.e., coastal and inland) and used in different types of application (i.e., occupancy-driven and process-driven). Section 3.2 provided information on electricity demand at facilities housing DG systems in the PG&E service territory and indicated how DG generator profiles might relate to site demand, especially in the case of generators classified as non-baseload. The purpose of this section is to examine the relationship between DG systems on particular distribution feeders. We are interested in determining two items: 1) the extent to which DG generation profiles naturally lend themselves to addressing the peak demand of the distribution feeder to which it is connected and 2) the extent to which blends of DG systems can be used to address not only the site demand, but also the distribution feeder demand. In developing blends of DG systems, we rely on the representative generation profiles established in Section 3.1 and the representative facility demand profiles established in Section 3.2. We have selected representative distribution feeders from each of the IOU service territories to demonstrate the results of our analyses.

### *Modeling and Analysis of a PG&E Feeder*

The first feeder analyzed is feeder PG&E B.[3] The SGIP DG system interconnected to the feeder is a 250 kW rated microturbine (MT). At the MT bus location, the 12.47 kV distribution line rating is 3.6 MVA. The feeder is located in Climate Zone 3. It borders on another feeder (PG&E C) analyzed in this project and located in Climate Zone 3. The initial feeder one-line as modeled in Power World contains 333 buses, 96 loads, and 3 capacitors. The total connected load is 8.14 MW. There are six (6) other generators specified in the feeder data set that are modeled as non-operational for this analysis because metered data have not provided for these units. Figure 3-19 shows the original one-line diagram for the PG&E B distribution feeder.

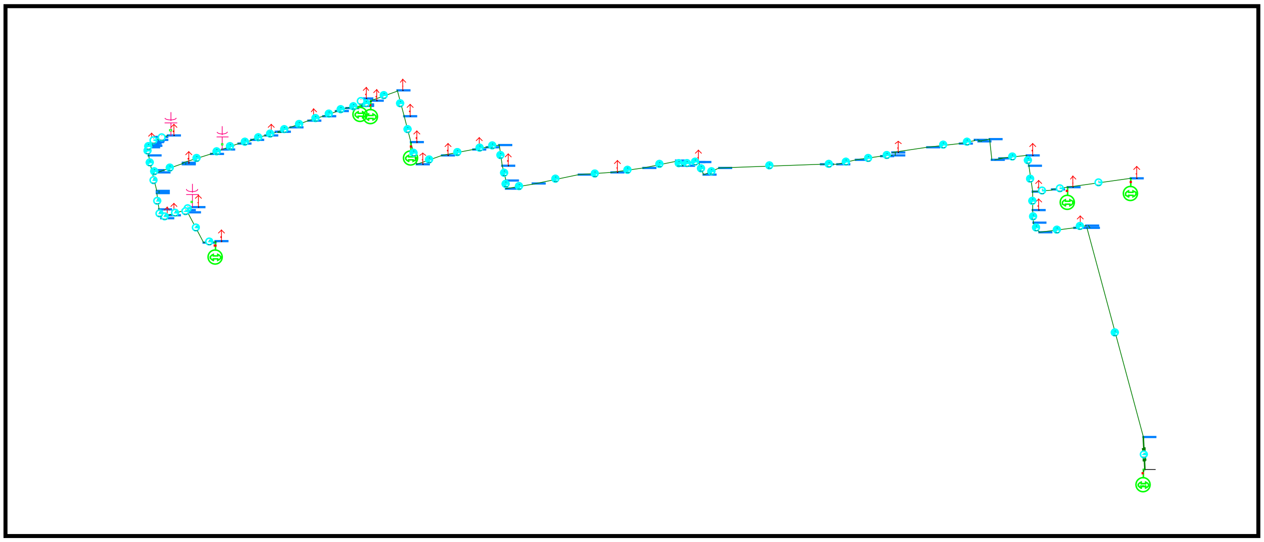
[3] We have masked the identify of the different distribution feeders and DG systems for which we have data in order to protect proprietary and confidential information.

**Figure 3-19: Original One-Line Diagram of PG&E B**



Three (3) capacitor banks are connected on the feeder. These are rated as one 1200 MVA unit and two-900 MVA units. The capacitor banks are located across the feeder; represented as pink capacitors in Figure 3-19. An equivalent circuit representing loads located on the main trunk three–phase distribution lines are modeled to reduce analysis. The model represents radial loads as located on the main trunk three–phase distribution line. Radial taps containing only load, not capacitors or generators, are "equivalenced" to the three-phase connection point on the feeder. The equivalent one-line model representation is shown in Figure 3-20. The resulting one-line model has 120 buses, 36 loads and the same number of generators and capacitors from the initial model. After the equivalent loading is completed, there is 3.4 MW of load on the DG generator bus.

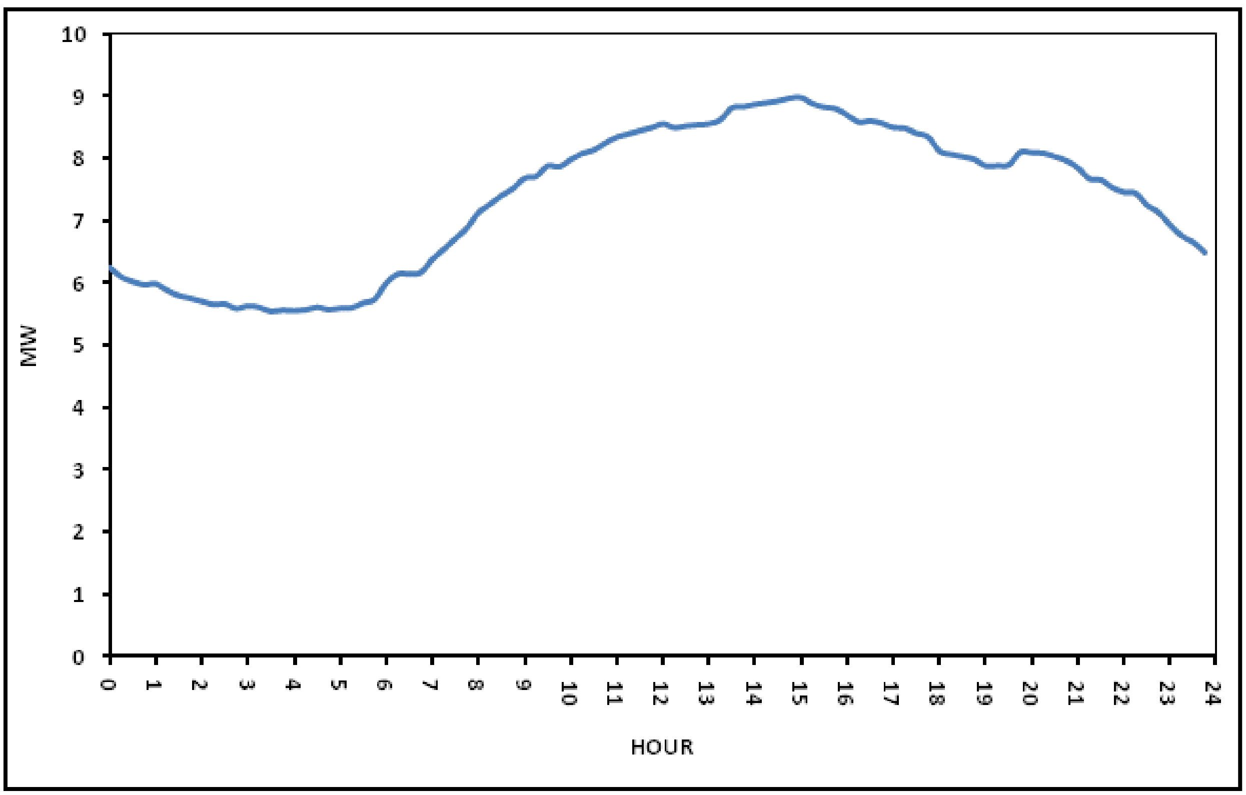
**Figure 3-20: Equivalent One-Line Diagram of PG&E B**



PG&E provided 15- minute and hourly load data for the feeder, which was converted to the time-step simulation function within Power World. The time-step function allows analysis of the load profile on the entire feeder over a time-period such as one day or one week, including visualization of additional overloads, bus voltages, and system MW (and MVAr losses). There are approximately four (4) months of data for the summer months (June to September) for the DG generators.

The peak load day for the feeder was extracted from the 15-minute data, and the MW Feeder demand and DG generation profile plotted. The feeder demand profile is shown in Figure 3-21 and the generation profile is shown in Figure 3-22. The peak load of 8.9 MW occurred on September 4, 2008. The outputs of the feeder demand and the DG generation are converted to a per unit basis[4] and plotted on the same axis to show how the DG generation profile correlates to demand. The results are depicted in Figure 3-23.

**Figure 3-21: Demand Profile for Feeder PG&E B**




PG&E B peaked on September 4th at approximately 2:30 P.M.. Because PV generation is maximized from the late morning to early afternoon, a 2:30 feeder peak makes PG&E B a good

---

4 Per unit basis and capacity factor are used interchangeably within this report. In both cases, the nomenclature refers to a normalization of the generator capacity relative to peak capacity

candidate for possible introduction of PV power on the feeder. The minimum demand on this day occurred at 4 A.M., and was just over 5 MW.

**Figure 3-22: Generation Profile for SGIP Generator on PG&E B (250 kW MT)**

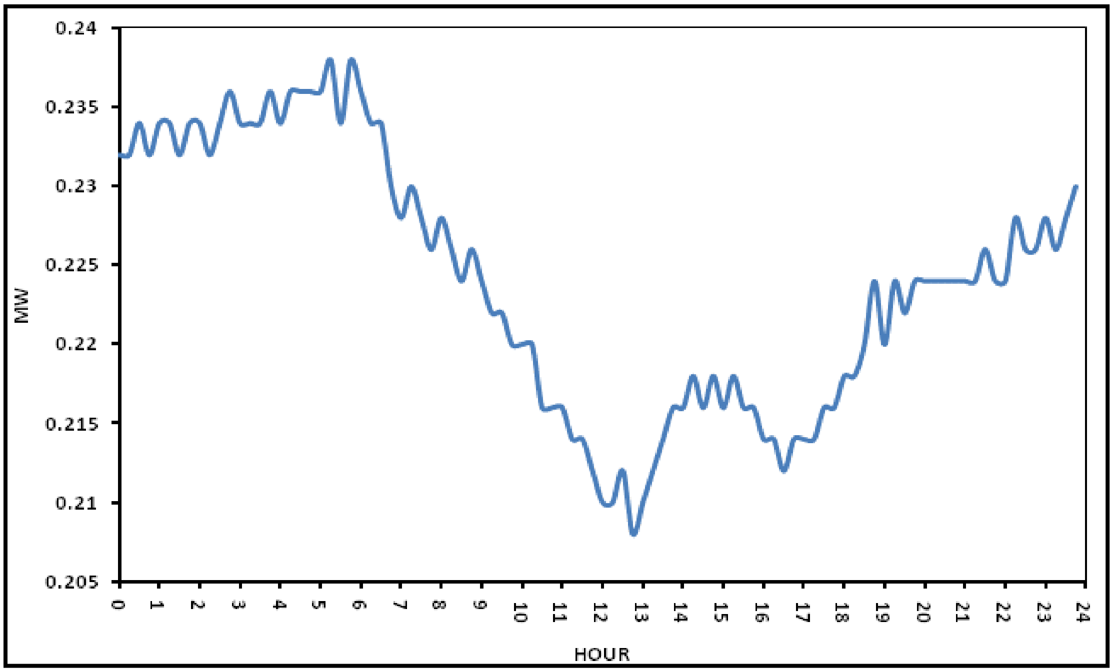
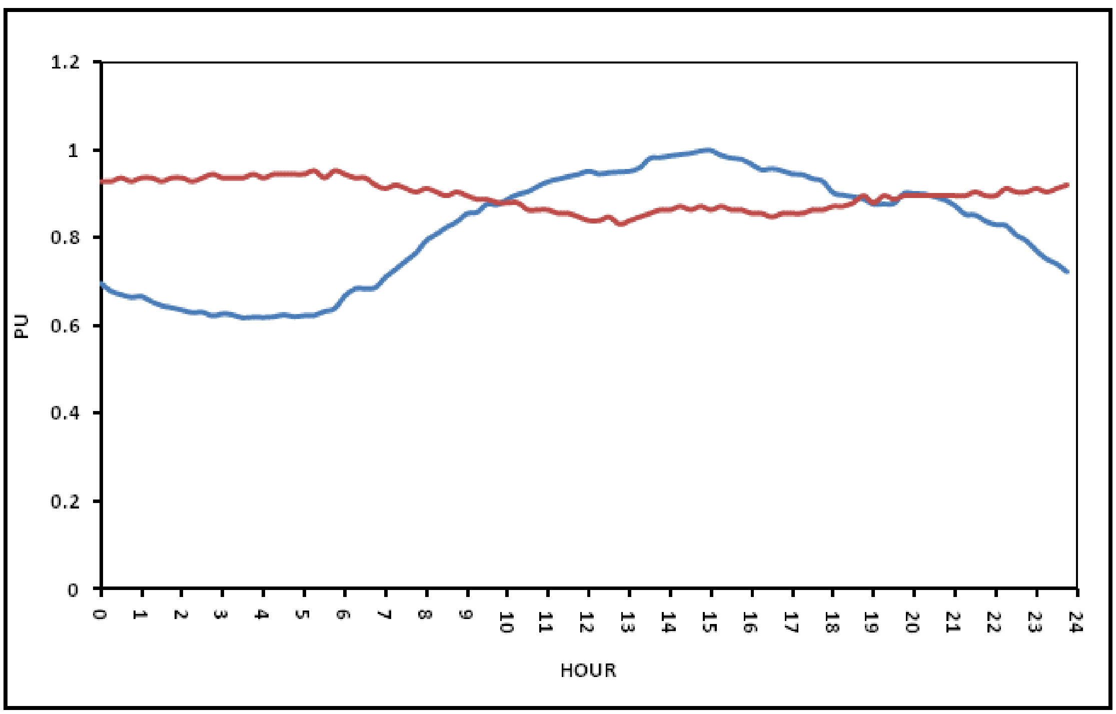



**Figure 3-23: Per Unit Representation of Generator Output Against Demand**

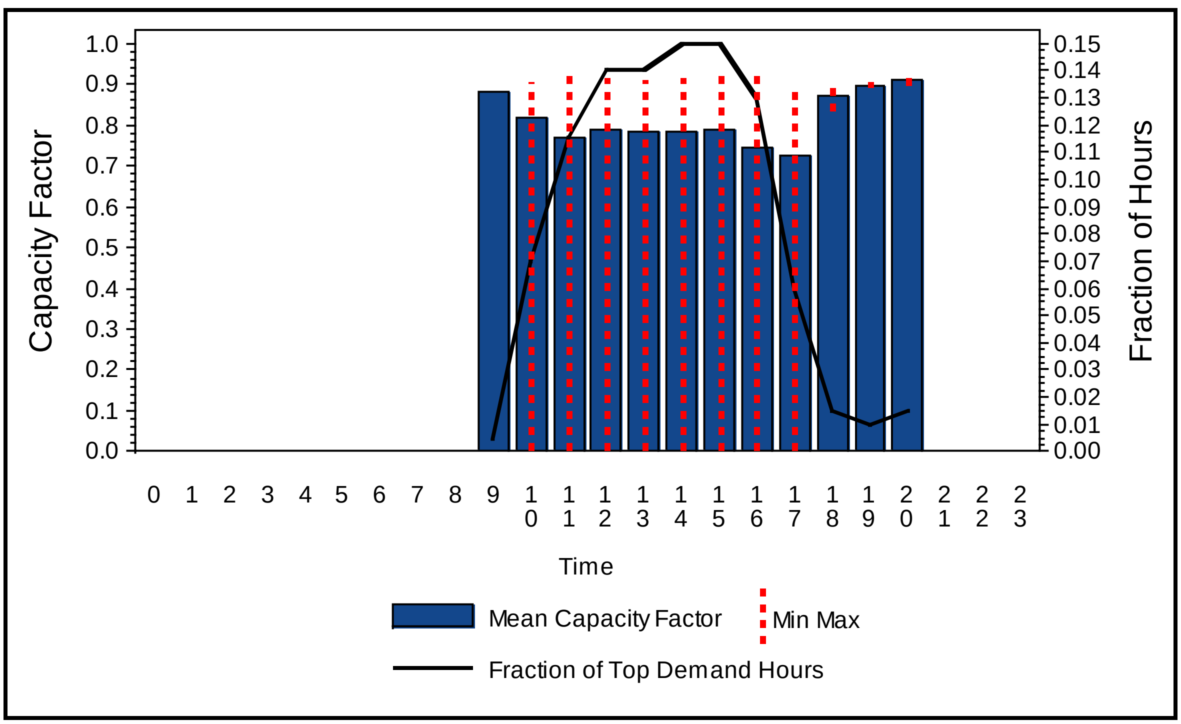


As seen in Figure 3-23, the maximum generation of the DG system drops by approximately 10% during the summer peak hours. This drop in output results from the effects of high ambient temperatures on the microturbine operation in hot climates. During the summer months, the air temperature increases significantly, which reduces the volume of air traveling through the microturbine and reduces power output. Note that the microturbine is not operating as a load following unit, but is acting as a baseload unit throughout the 24 hours.

Investigating feeder demand and DG generation on the peak day offers one method to evaluate the DG's effectiveness during hours when the feeder is critically loaded. A potentially more representative method of evaluating the effectiveness for DG to meet demand during critical periods is to examine system performance during the top hours of demand; not just the top day. This was done by first determining the time and day of the top 200 hours of feeder demand and the DG generation during those hours. The resulting generation is then divided by the system capacity during each hour to determine an hourly capacity factor. This method also helps to verify how representative the peak day is of both feeder demand and DG generation.

Figure 3-24 shows the mean capacity factor by hour for the microturbine on PG&E B during the top 200 hours of demand on that feeder. We have also shown the minimum and maximum capacity factor that occurs during each hour. The average capacity factor is slightly lower during the hours in the middle of the day; driven down by higher temperatures and the MT being off line on June 9, 10, and 11 when there was occurrence of some of the peak hours.

**Figure 3-24: DG Generation during top 200 Hours of PG&E B Feeder Demand**



The distribution line at this DG bus is rated at 3.6 MVA, and it is assumed there are no planned upgrades at this bus. In general, line loading should not exceed 100% of line rating under normal operating conditions. The microturbine's potential performance as a load following system is from the manufacturer's data. The analysis on the performance and capability of the DG generator on this type of feeder includes:

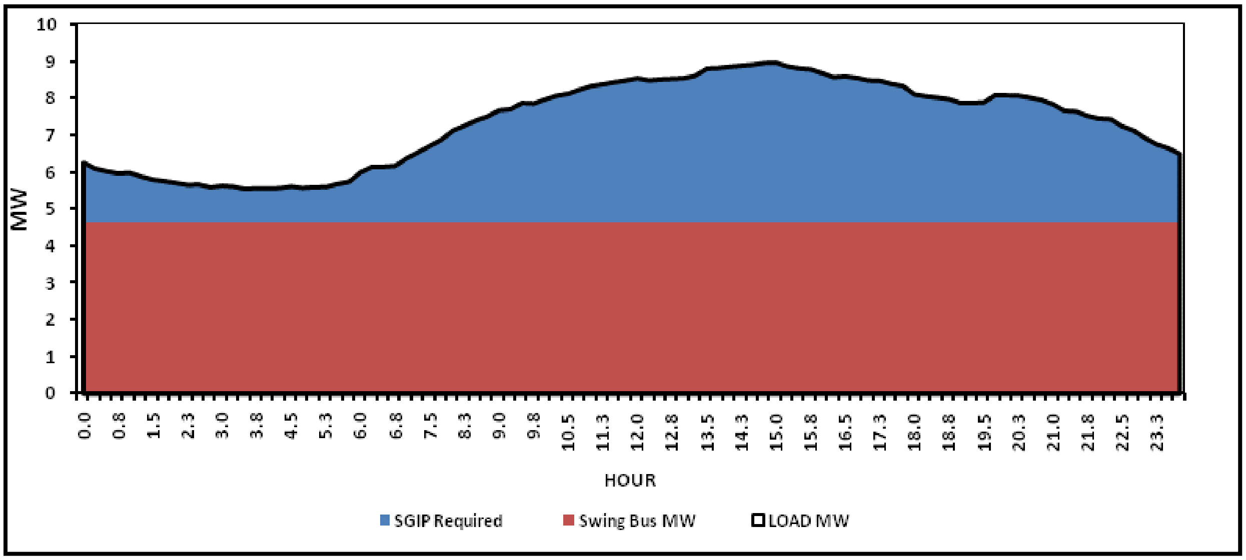
- Ramping ability and requirements
- MW level of generation allowed before overloads occur
- Minimum output required for load following operation to be performed
- Energy output from the load following generator in 24 hours
- Change in line losses with and without generator operating
- Call-for power capability

Two specific tasks are considered in analyzing the ability of the DG resources to address feeder peak demand and respond to a utility call for power. The first is scaling the microturbine capacity higher to test the DG resources ability to provide load following. The second task is diversifying the generation profile by adding additional renewable energy resources to the feeder. In the original feeder configuration, the Swing Bus or substation generator provides the excess power not supplied by the DG unit. When power is supplied from DG units located near or at load centers, there is a reduction in transmission, sub-transmission, and feeder losses. We scaled the original DG generator to a suitable size to test load following capability. We added additional DG generators to the feeder to provide power, which would smooth the output from the Swing Bus. In PG&E B, the DG unit is a microturbine. We scaled the output from the microturbine until the swing bus output remained constant.

***<u>Task 1: Analyze a Larger Microturbine to Provide Load Following</u>***

Task 1 analyzes the impact of increasing MT capacities on a feeder for load following capability. The original capacity of the MT on the circuit was 250 kW. This was too small to test load following capabilities, so the MT capacity was increased for this analysis. While the Swing Bus provides a fixed generation pattern during the peak day period, the microturbine serves all remaining load. The larger MT operates at 80% of its summer rating so that the MT provides capacity to increase or decrease generation to follow load. There is a minimum DG generating capacity that affects the Swing Bus minimum power. In Figure 3-25, the blue and red blocks show the contribution of the DG system and swing bus or substation generator, respectively, to meet the load.

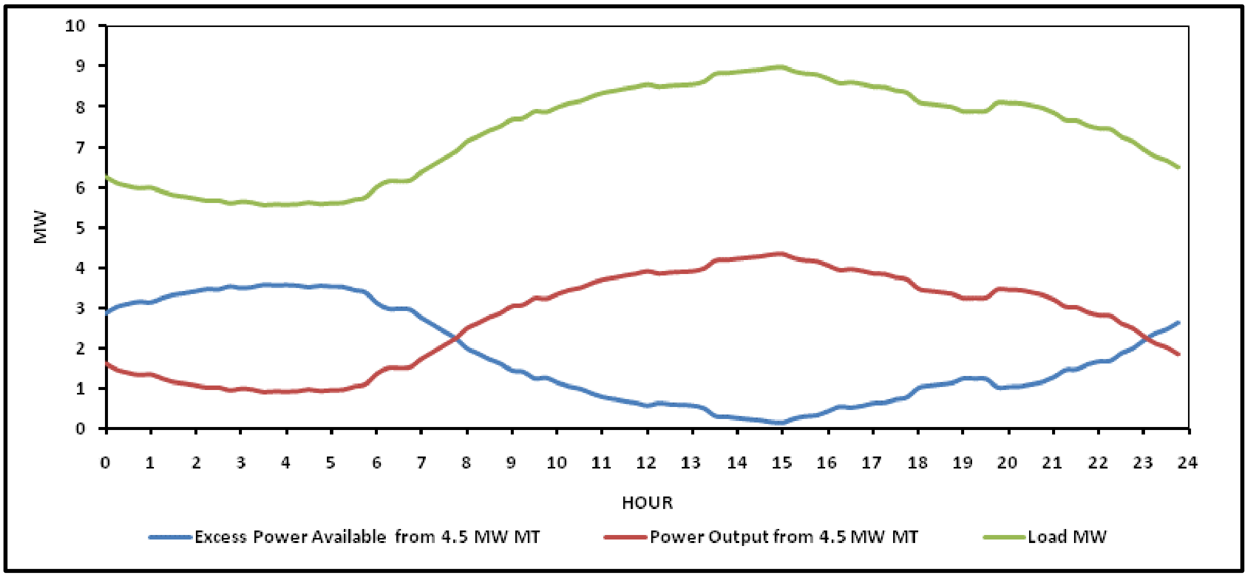
**Figure 3-25: Demand Profile and the Contribution of Each Generator to the Profile**




The Swing Bus generator size meets the difference between maximum and minimum load and meets the load of the bus to which it is connected. If the generator output exceeds the line capacity limitations, the generator size is reduced or limited to remain under 100% loading. If the difference is greater than the line capacity, the generator output is modeled at maximum capacity until less than maximum is required. The Swing Bus then increases its output to meet the demand. These generator limits are specified in the original generator profile calculations. The line percentage loading is analyzed as an output from the Power World time step analysis to find any unexpected overloads in other parts of the system. The maximum difference between minimum and maximum load is approximately the same as the line capacity (3.6 MW). The generator size of 4.5 MW takes into account the size of the load on the connected bus and the line capacity limits.

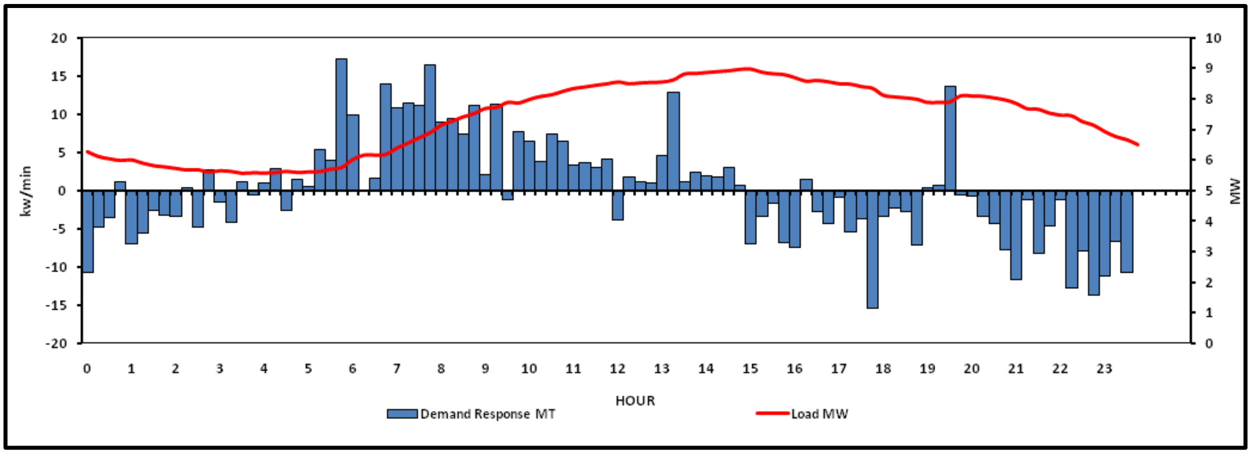
The 15-minute demand and generation profiles were created and simulated over a 24-hour period. There were no additional overloads created on the system using this configuration and the bus voltages remained within normal limits. The total system MW losses were also calculated. If the generator is rated at 4.5 MW, there is excess power. The generator output profile and the excess generator power is plotted on Figure 3-26. The excess power is assumed to decrease by 10% during midday hours.

**Figure 3-26: Output Power from the SGIP Generator with the Excess Power Available while Load Following**




Microturbines can dispatch to load follow, but at least in the SGIP, tend to generate at a constant output. The MT ramp rate determines the potential ability of a MT to provide this service. For this analysis, the ramp rate is calculated over 15-minute increments in kW/min and plotted in Figure 3-27 over a 24-hour time period for the peak day. The ramp rate is the difference in power generation from one 15 min period to the next 15 min period divided by 15 minutes.

**Figure 3-27: Ramping Required from the 4.5 MW MT Load Following System**



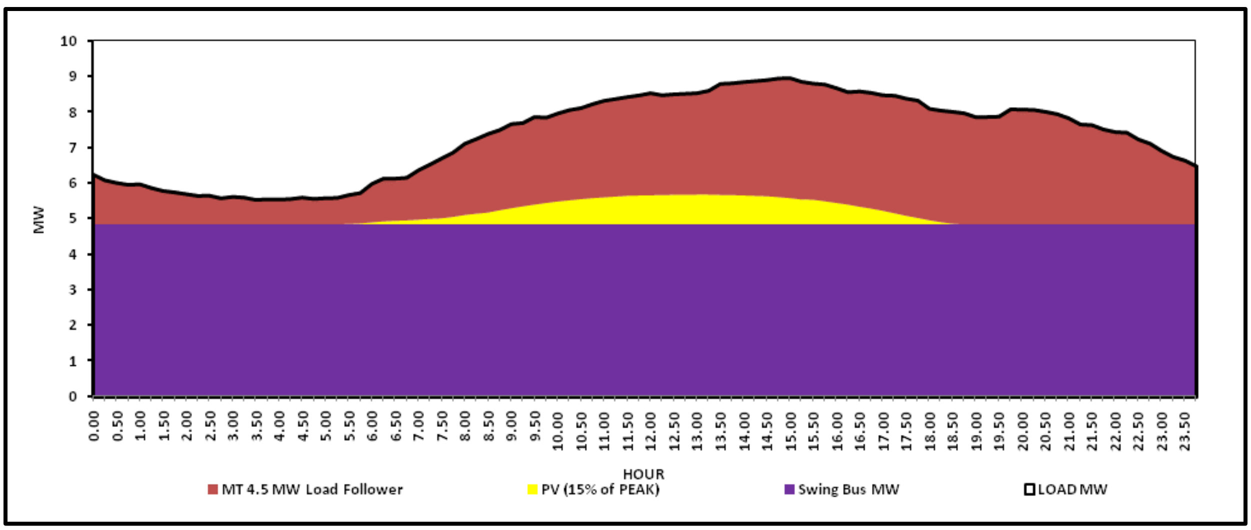

The maximum ramp up and ramp down of the microturbine during any 15- minute period is approximately 15 kW per min. The maximum change in 1 hour is approximately 683 kW up and 748 kW down. The MT ramp-up and ramp-down capability averages 137.5 kW/min or 8,250 kW/hour. As a result, the MT is within the ramping capability to meet the varying load on this feeder.

***Task 2: Diversify the Generation Profile for Load Following***

The second task examines adding a high (15% of feeder peak demand) penetration of distributed PV along the feeder that decreases the mid-day load in addition to adding a scaled-up microturbine for load following capability. The PV generators are distributed along the feeder as a percentage of PV at each loaded bus. For example, if a bus has 4 MW of peak load, and 15% of PV is added as a percentage of peak load, 0.6 MW of PV generation is added at the same bus, as long as the line capacity exists. The PV serves the load at the bus and appears as a load reduction by the Swing Bus. This analytical method indicates that even at a high PV penetration, there should be no additional overloads since 15% of the bus load is served by PV. Further dynamic, stability, and fault current analyses would be required to determine if this penetration is obtainable, but was not done as it fell outside the scope of this study. For the same reason, this study does not investigate any power quality, or power management issues other than thermal capacity of the distribution feeders.

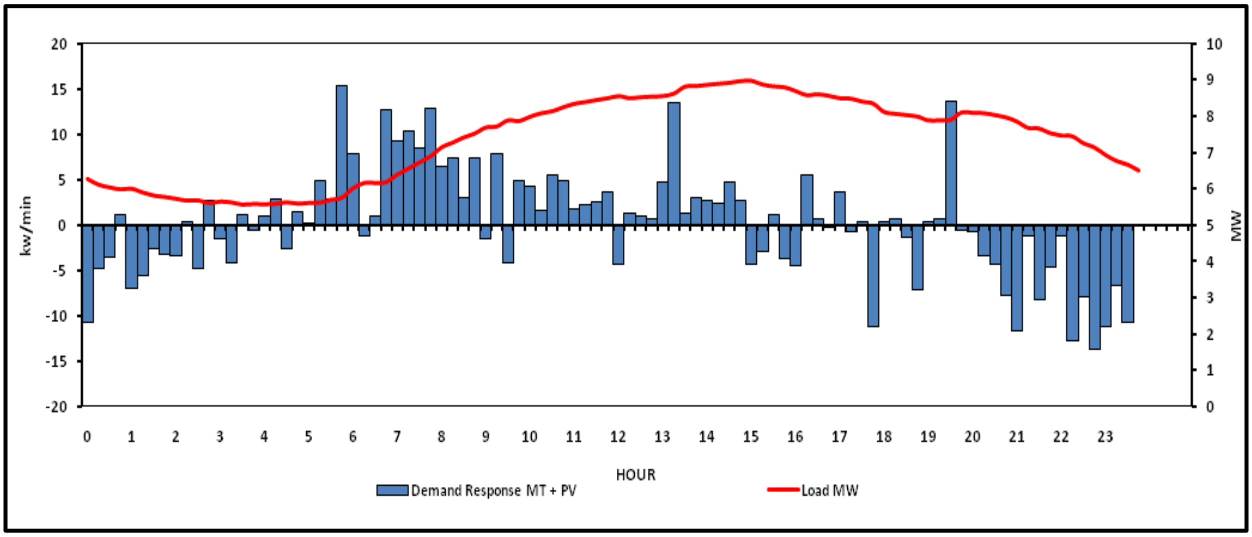
The system peak load is 8.9 MW with 6.7 MW of the peak load served by PV resources. The microturbine dispatch varies with the addition of the PV. If online, the MT minimum generation remains at a 20% minimum output and the hour-to-hour dispatch is affected by the PV generation. The new demand profile is shown in Figure 3-28. The purple and red blocks represent the Swing Bus generator and MT, respectively, and the yellow is the PV generation.

**Figure 3-28: New Demand Profile with High PV Penetration Dispersed Across the Loaded Buses**



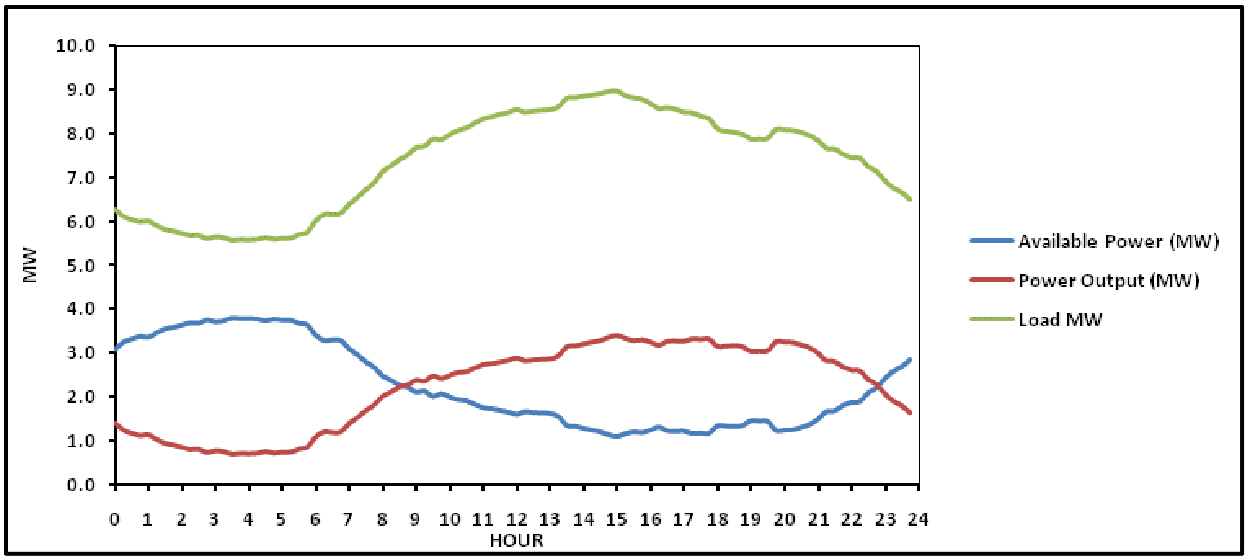

PV generation is treated as demand reduction by the Swing Bus. The PV generation peaks shortly before the demand reaches its peak. The MT ramp rate to meet this new demand profile is plotted in Figure 3-29. Using the same method as developed earlier, the new ramp rate is calculated over each 15-minute period.

**Figure 3-29: Demand Response Required for Microturbine Combined with PV**




The MT ramp rate under this scenario increases but does not exceed 15 kW/min which is below the observed and rated ramp rate for a microturbine. The maximum ramp up rate over a one-hour period is 917 kW and the ramp down is 820 kW. The available power from the DG generator and the PV is plotted in Figure 3-30.

**Figure 3-30: Available Power from the DG Generator Combined with PV**




The power from the MT, when combined with power from the PV system, follows the same generation profile as the MT operating alone during the morning and evening off-peak hours. The required amount of MT generation is reduced when operating with the PV. The Swing Bus provides a smaller minimum load when combined with PV, due to the demand reduction effects of the PV. The microturbine generates more power during the off-peak hours and provides less power to be available to the utility as reserve capacity. The opposite type of situation develops during the peak hours with respect to the power needed from the MT. As the feeder demand reaches its peak, the PV system is nearing its peak output. As a result, little power is required from the microturbine to meet the feeder demand. The energy (MWh) output from each operating scenario over the 24 hours and for each generator is shown in Table 3-4.

**Table 3-4: Overall Energy Output Calculations**

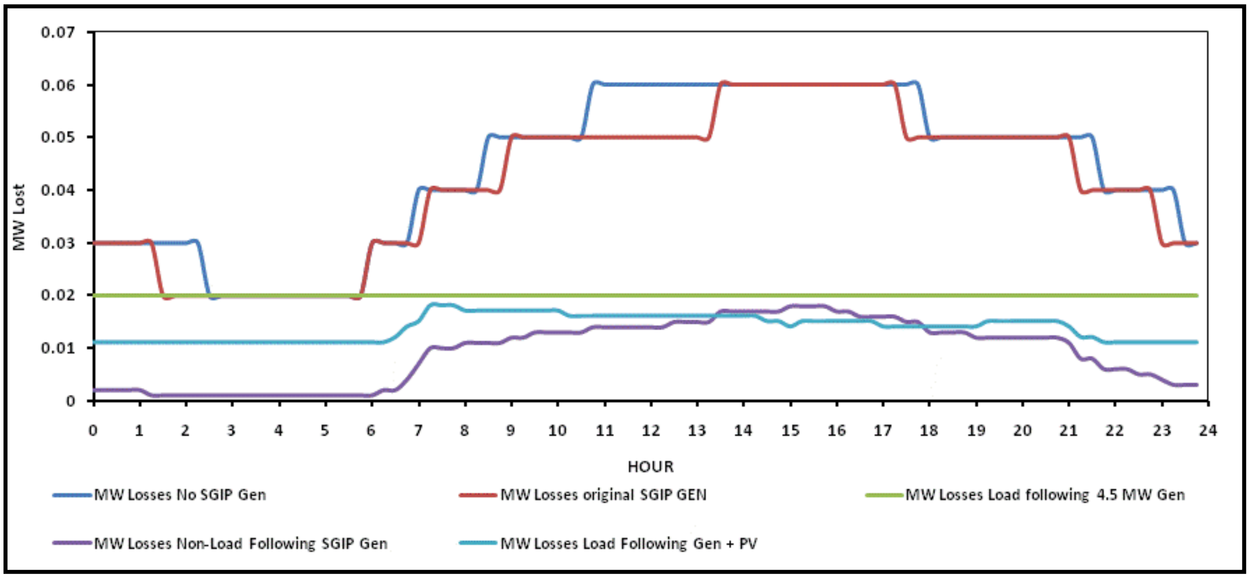
| Situation | Swing Bus MWh over 24 Hours | Microturbine MWh over 24 Hours | PV MWh over 24 Hours |
|---|---|---|---|
| No SGIP Generator | 177 MWh | N/A | N/A |
| Load Following MT (4.5 MW) | 116 MWh | 61 MWh (56% of Potential MWh) | N/A |
| Load Following MT (4.5 MW)+ 15% PV | 116 MWh | 54 MWh (50% of Potential MWh) | 7 MWh (20% of Potential MWh) |

The baseline data set reflects the feeder operating without any DG units. In this situation, the Swing Bus baseline generation over the 24-hour period is 177 MWh. When a 4.5 MW load-following MT system is dispatched to meet demand, the Swing Bus generation is reduced to 116 MWh, or 65% of the energy. The load-following microturbine provides 35%, or 61 MWh over the 24 hours. If the microturbine operates at full power for 24 hours, the total generation supplied by the MT is 108 MWh (i.e., 4.5 MW for 24 hours equals 108 MWh). In this situation, the MT provides 56% of its available energy in 24 hours. In the third scenario, the load-following MT is combined with enough PV capacity such that the PV capacity can meet 15% of the feeder demand. As a result, the Swing Bus provides 65% of the total energy, the microturbine provides 31%, and the installed PV provides the remaining 4%. The MT generates 50% of the total potential MWh. The losses over the 24-hour period are shown in Table 3-5 and plotted in Figure 3-31.

**Table 3-5: Average MW Losses for Each Type of Operation**

| Type of Operation | Average MW Loss | % Change From No DG |
|---|---|---|
| MW Losses NO DG | 0.044 | 0% |
| MW Losses Original DG | 0.041 | -7% |
| Losses Load Following 4.5 MW DG | 0.007 | -84% |
| Losses non-Load Following 4.5 MW DG | 0.006 | -85% |
| Losses Load Following 4.5 MW DG + PV | 0.006 | -85% |

**Figure 3-31: MW Losses over 24 Hours in Different Configurations of Generation**




For the two original scenarios of no generator added (all demand served by the Swing Bus) and the 250 kW generator added, the losses follow a similar profile over the 24-hour period. As shown in Table 3-5, the change in losses from no DG system to the originally added DG generator is approximately 7%. When the load-following 4.5 MW microturbine replaces the original generator, the loss profile becomes a straight line and the average loss is reduced by 84%. The Swing Bus provides a constant power; therefore, the losses are constant. When the generator scales up but follows a constant output profile, the losses change with the load. In this scenario, the Swing Bus provides the small load changes and the average losses are reduced.

*PG&E B Summary*

PG&E B is an early afternoon peaking feeder. The feeder peak occurs approximately one hour after PV power output peaks. The change in demand on a 15-minute basis is small enough that a microturbine easily meets demand above what can be provided by the PV output. When the MT is combined with PV capacity, it allows the microturbine output to be reduced. In turn, this leaves sufficient power available in the day either to answer a "call for power" from the utility or to address a drop in power from the PV systems in the case of cloud cover or an inverter outage.

### *Modeling and Analysis of an SCE Feeder*

The sample SCE feeder (SCE C) is located in Climate Zone 13 (characterized by the climate of the City of Visalia in the Central Valley). The SGIP DG system interconnected to the feeder is a 250 kW ICE generator. The feeder as modeled in Power World contains 269 buses, 47 loads and 2 capacitors (see Figure 3-32). The total connected load is 6.96 MW. An equivalent circuit was developed using the same methodology as described above for the PG&E feeder. The equivalent one-line model representation (see Figure 3-33) shows 109 buses, 11 loads and the same number of generators and capacitors from the original one-line model.

**Figure 3-32: One-Line Diagram for SCE C**

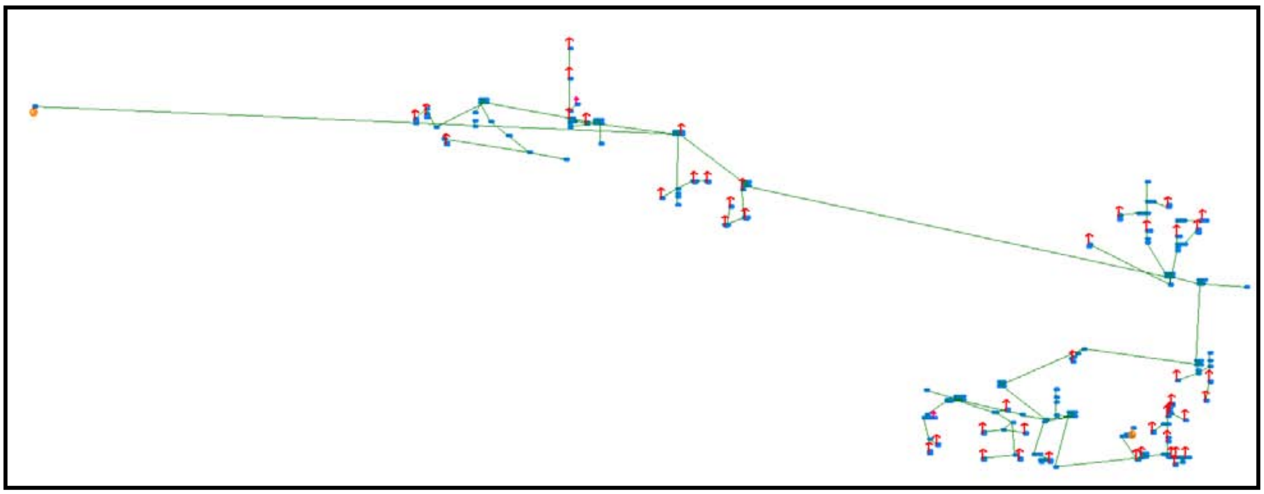
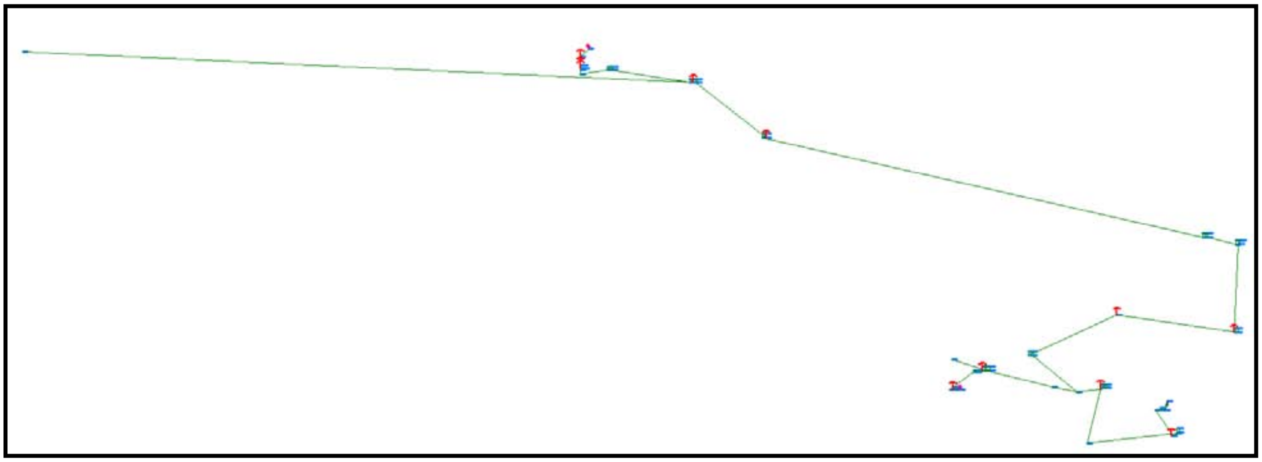


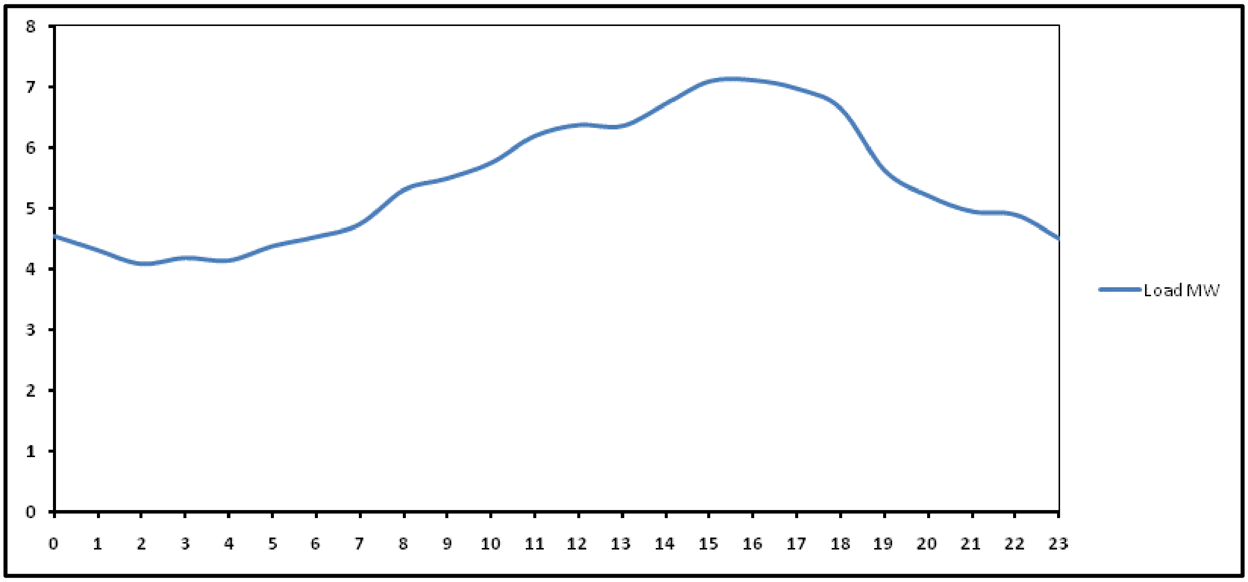
**Figure 3-33: Equivalent One-Line Diagram for SCE C**



SCE provided four months of data for the feeder covering the summer months from July to September 2008. Although 15-minute generation data was available for the DG systems, only hourly demand data was available for the SCE feeders. The data set for the time step simulation was created by modeling the load for the four 15-minute period of each hour. As a result, the load steps from hour to hour rather than from 15 minute to 15 minute. The DG generation connection is rated at 2.3 MVA, which limits the potential for excess generation. The maximum change between minimum and maximum demand is 2.8 MW. Potentially, 0.5 MW is not served by the DG generator, and an alternative solution must be found.

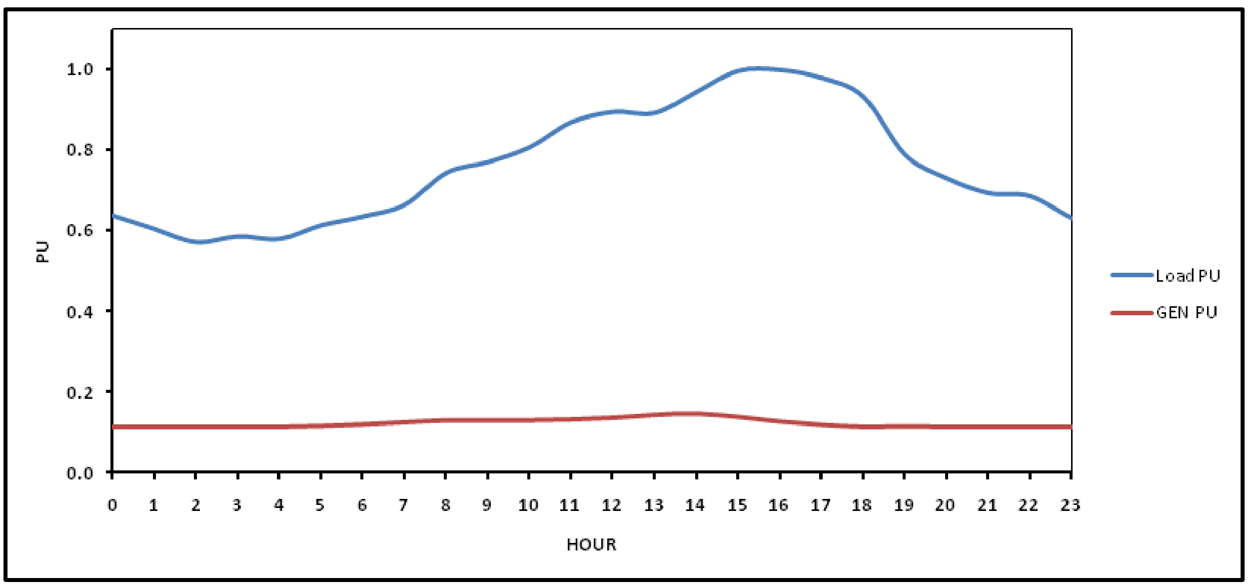
The peak demand day is extracted from the 15-minute data. The demand profile is shown in Figure 3-34. The peak demand of 7.1 MW occurred on July 10, 2008 at 4 P.M.. The peak at 4 P.M. falls beyond the time-period when PV systems generate their maximum output. A minimum demand of 4.1 MW on July 10 occurs at approximately 2 A.M..

**Figure 3-34: Demand Profile for Peak Day (July 10, 2008) on SCE C**



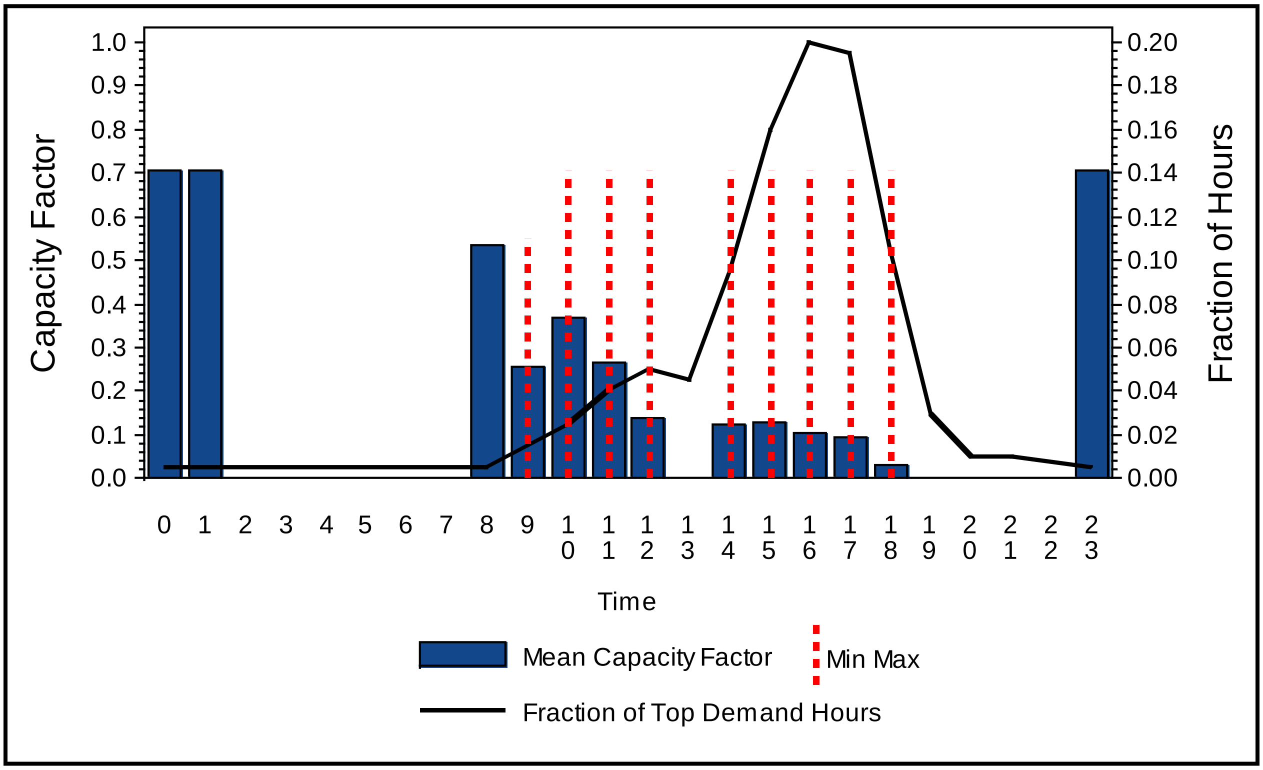

To understand how the DG generation correlates to demand, we converted the outputs to a per-unit base and plotted them on the same axis in Figure 3-35. The original DG generator is a 250 kW ICE unit that operates at a varying output of 10 to 15% of the maximum rating across the entire day.

**Figure 3-35: Demand and Generator Data in per Unit Form for SCE C**




In 2008, the ICE unit located on SCE C operated somewhat sporadically as evidenced in Figure 3-36. However, during the same hours in 2007 and 2009 the same ICE system showed a nearly constant output at 70% of rated capacity.

**Figure 3-36: DG Output in 2008 during Top 200 Hours of Demand on SCE C**




The majority of top demand hours on this feeder occurred at 4 or 5 P.M.; much like the peak day.

The ICE unit normally operates at constant power output and is not impacted by high ambient temperatures. The ICE system also does not have minimum power requirements. The DG generation connection to the distribution line is rated at 2.3 MVA and should not exceed 100% of capacity in normal operating conditions. The ICE potential performance as a load-following unit is from the manufacturer's data. The study tasks for evaluating the ability of DG resources to meet feeder demand and respond to a call for power are the same as the PG&E feeder:

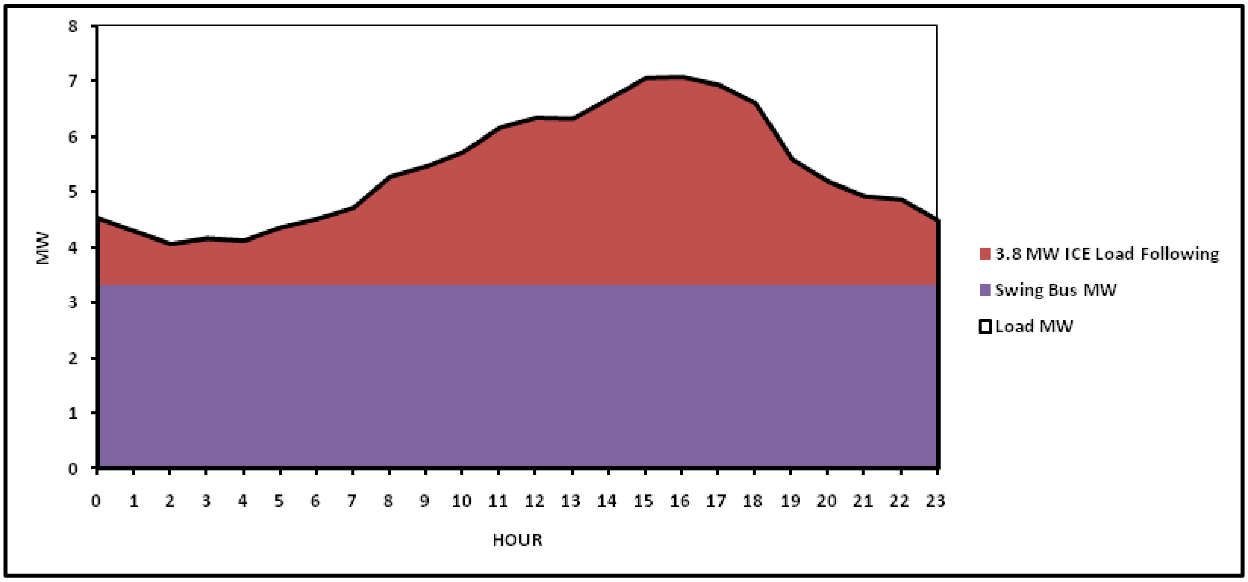
- Task 1: Operation of the ICE as a larger load-following unit
- Task 2: Operation of the ICE as a load-following unit in combination with other DG resources.

***Task 1: Analyze a Larger ICE Load-Following System***

The SCE C distribution feeder originally contains a 250 kW ICE unit. We increased the capacity of the ICE system to evaluate its ability to provide potential load-following capacity. The Swing Bus provides a fixed generation pattern during the peak day period while the ICE serves all remaining demand. If the feeder line rating of 2.3 MVA is exceeded, the Swing Bus serves the demand that exceeds the feeder line capacity.

The generation patterns of the Swing Bus and larger ICE unit are plotted in Figure 3-37. The load profile for July 10 is shown across the top of the graph in black. The red and purple blocks show the generation of the DG unit and Swing Bus in meeting the load, respectively.

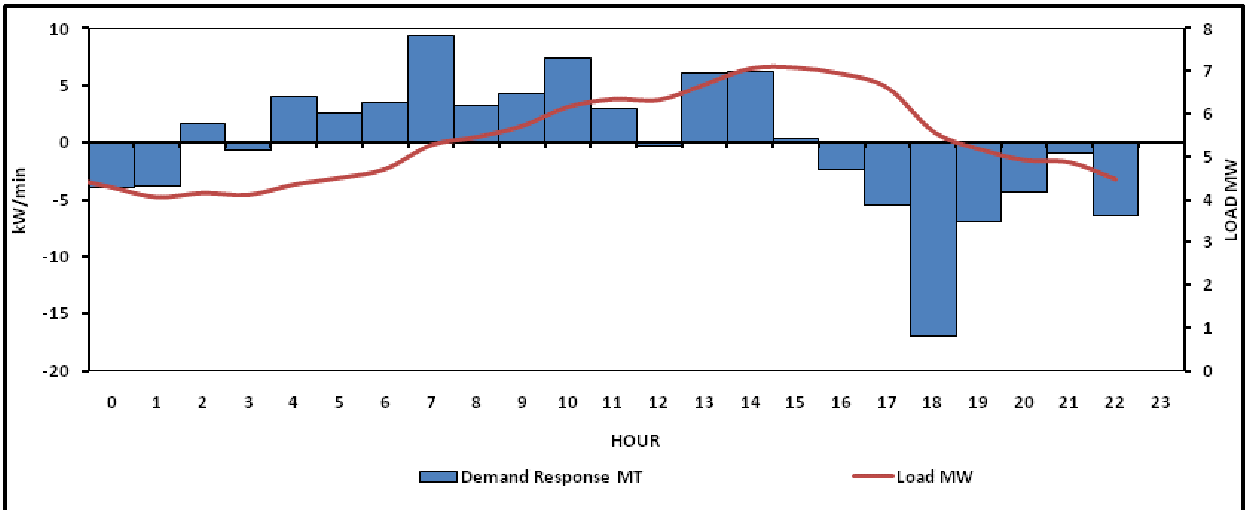
**Figure 3-37: SCE C Demand Profile for the Peak Demand Day (July 10, 2008)**




The DG unit met the difference between minimum and maximum load. The maximum generation of DG unit is 3.8 MW and the maximum difference between minimum and maximum load is 3 MW. We modeled the ICE operating at 20% minimum at time of minimum demand.

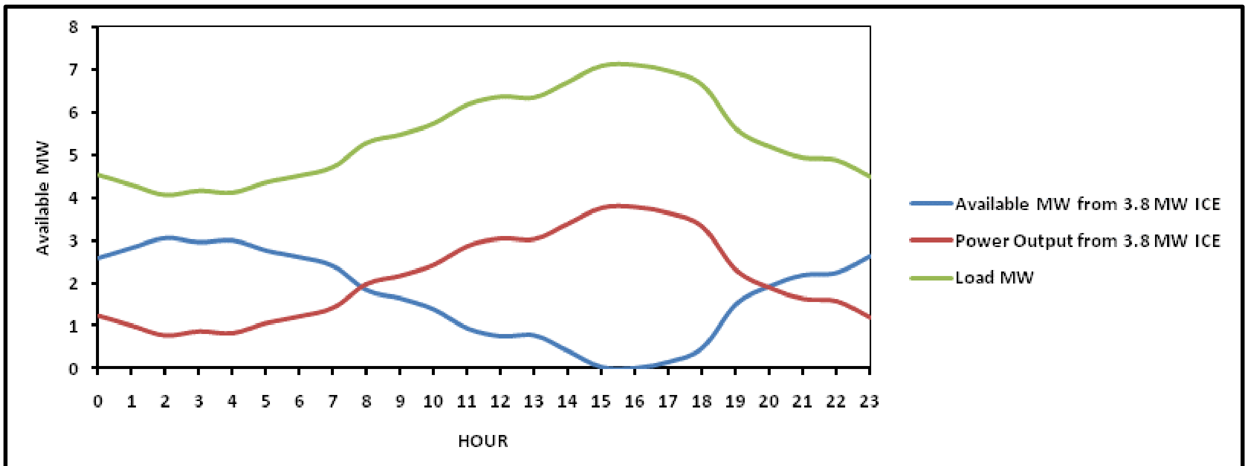
Although the feeder peak occurs in the evening, when PV provides no additional demand benefit, the PV system acts to reduce demand in daytime hours. As mentioned earlier, there is smaller peak at 12 noon when PV generation is near its peak generation. The 15-minute demand and generation profiles are simulated over the 24-hour period. No additional overloads occur and the bus voltages remain within normal limits. The ramp rate in kW per minute for the ICE unit is shown in Figure 3-38 for each 15-minute period.

**Figure 3-38: Ramping Required from 3.8 MW SGIP ICE Unit when Operated in a Load Following Configuration on SCE C**




Since SCE provided hourly and not 15-minute data, the graph of the ramp rate is not as accurate as the PG&E feeder graph. The maximum rate of change for the 3.8 MW ICE unit is approximately 17 kW/min. A 17 kW/minute ramp rate is within the observed and rated ramping capabilities of an ICE unit The excess available power and the power from the ICE system is graphed in Figure 3-39.

**Figure 3-39: Excess Power Available from the 3.8 MW ICE System on SCE C**

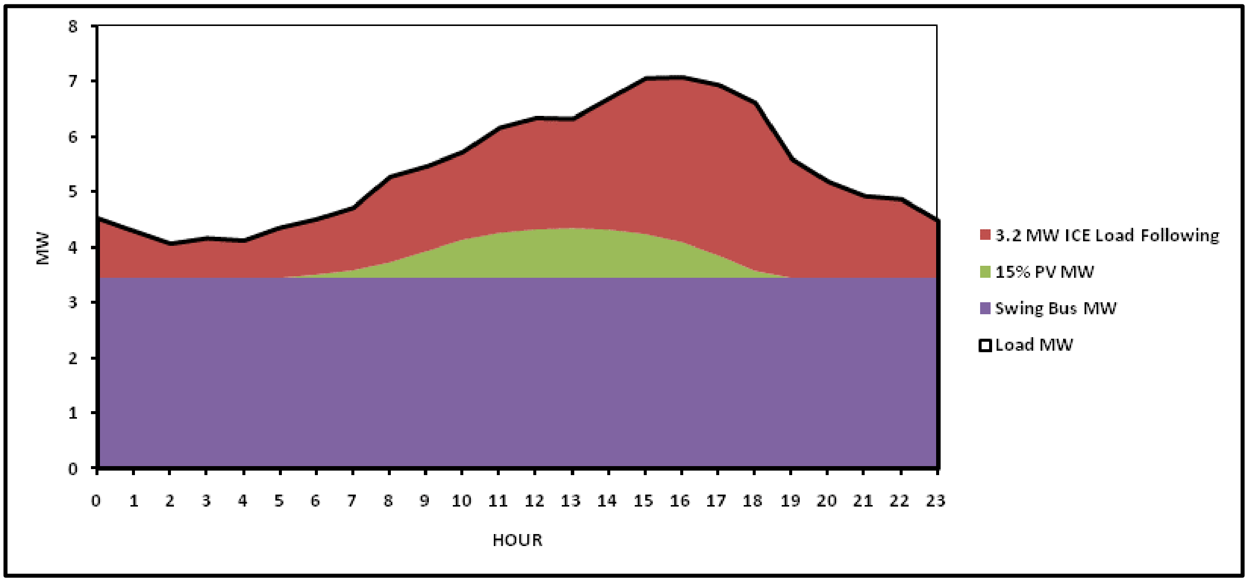



The DG unit dispatches and follows the load for the full 24 hours. At 4 P.M., it reaches maximum output. No excess power is available during the peak hour. The excess power from the ICE during off-peak hours also provides ramping capability.

***Task 2: Diversify Generation Profile for Load-Following***

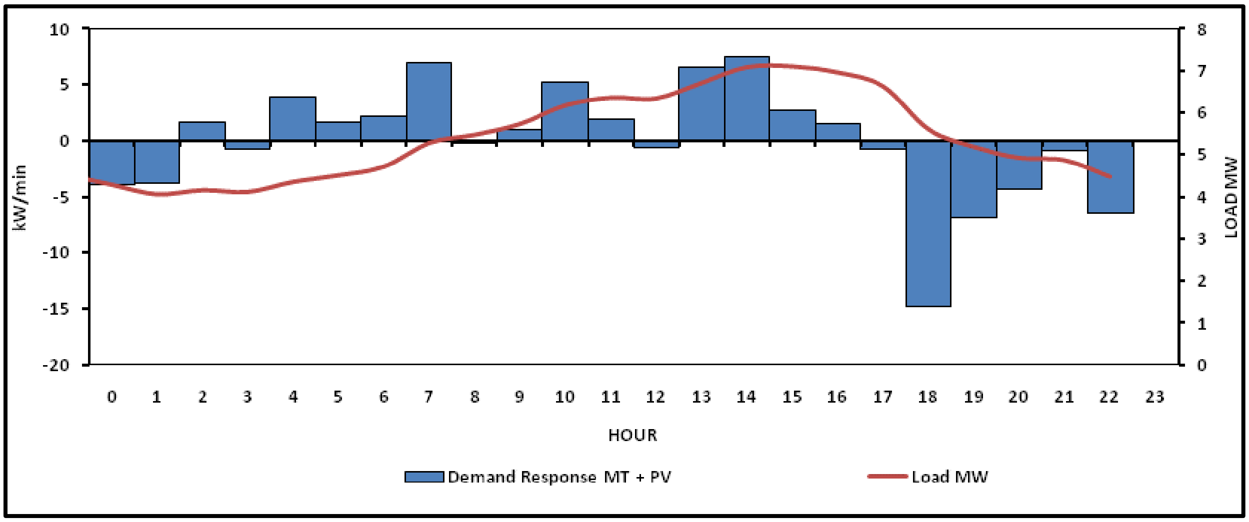
The second task combines high penetration of distributed PV with the scaled-DG unit to provide excess power during the day for load-following operation. PV generation is added up to 15% of the peak demand. The feeder peak is 7.1 MW, therefore 1.1 MW of PV is dispersed across the feeder. The system bus voltages are within normal limits. The system peak is 3 hours later than the PV peak. There is a smaller peak of 6.4 MW at 12 noon. The PV unit generates at 83% of its maximum rating at this time. The stacked PV unit, Swing Bus and ICE generation is shown in Figure 3-40. The PV is the green block. The DG ICE unit generates additional power above the Swing Bus and the PV unit until the feeder line reaches rated capacity.

**Figure 3-40: Stacked Generation Plot of the SCE C Feeder with ICE and 15% Dispersed PV**



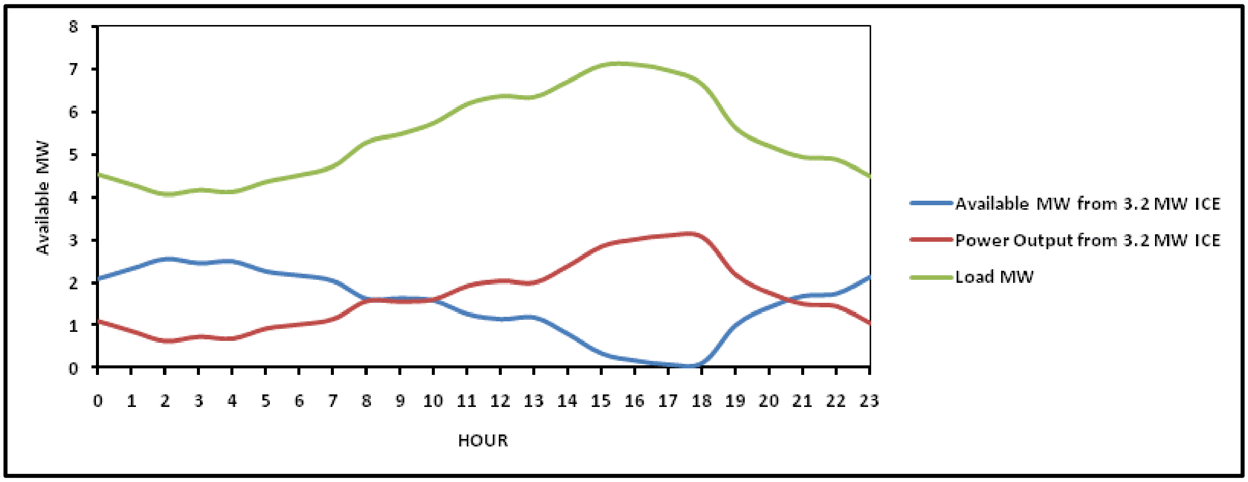

The ramp rate is calculated as previously described over each hour period (divided by 60 to give kW/minute). The resulting ramp rate requirement is shown in Figure 3-41. The maximum ramp down rate for the ICE unit is approximately 15 kW/min and the maximum ramp up rate is under 10 kW/min. A ramp rate of 15 kW/minute is within observed and rated abilities for an ICE unit.

**Figure 3-41: Ramp Rate Requirements for the ICE Unit when Paired with PV on SCE C**




The available power from the combined ICE generator and PV system is graphed in Figure 3-42. The available power from the ICE and the combination of the ICE/PV systems follows approximately the same profile during the early morning hours. The available power from the PV/ICE combination is reduced as the demand increases. However, as the demand increases approaching noon and early afternoon, output from the PV system also increases. Consequently, generation from the PV system can replace power otherwise needed from the ICE unit to meet peak demand. This leaves excess ICE capacity available as potential reserve capacity for the utility during peak hours. As PV generation decreases in the later afternoon, the available ICE capacity is reduced to 3.2 MW (from 3.8 MW) to satisfy the maximum difference between minimum and maximum demand. The ICE system has power available for the majority of the day; with available generation reducing towards the 4 P.M. feeder peak, but increasing after the feeder peak demand diminishes in the evening.

**Figure 3-42: Available Power Plot from ICE and PV on SCE C**




The energy output from each operating scenario and for each generator is calculated and shown in Table 3-6. The baseline assumes no DG generators are operational on the feeder. For this scenario, the energy produced over the 24 hours by the Swing Bus is approximately 130 MWh. When a 3.8 MW load-following ICE generator is dispatched to meet all demand above the minimum, the Swing Bus generation is reduced from 130 MWh to 80 MWh, or 62% of the feeder energy. The remaining 50 MWh comes from the ICE generator. If the ICE operates continually at full power for 24 hours, the total energy is 91 MWh (i.e., 3.8 MW x 24 hours equals 91 MWh).

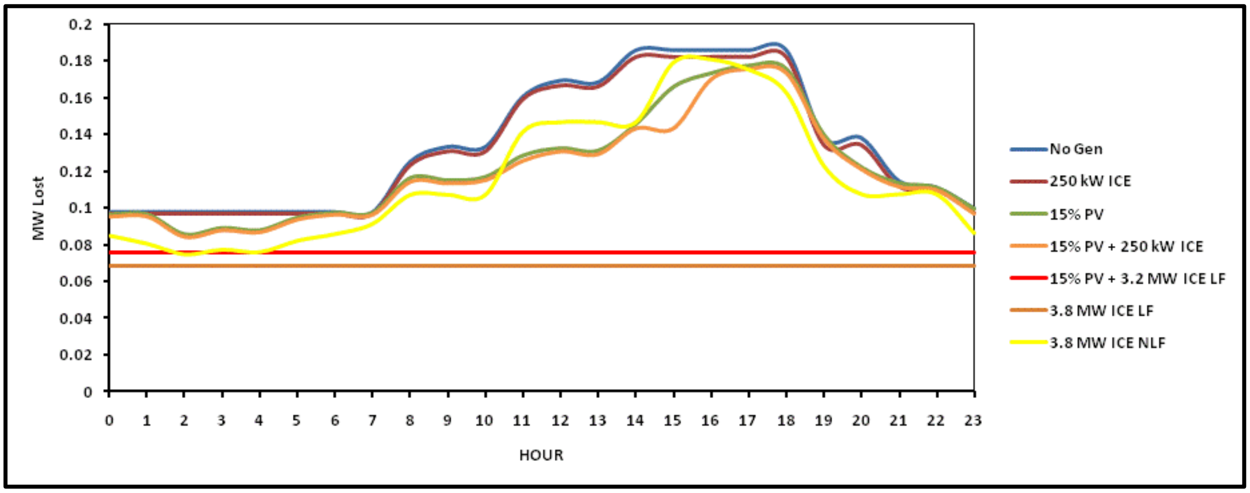
When the load-following ICE is combined with a 15% penetration of PV, 82 MWh (or 63% of demand energy) comes from the Swing Bus; 40 MWh (31%) comes from the ICE; and 7 MWh (6%) comes from the PV system.

**Table 3-6: Energy Available and Energy Output over 24 Hours for SCE C**

| Scenario | Swing Bus MWh over 24 Hours | ICE MWh over 24 Hours | PV MWh over 24 Hours |
|---|---|---|---|
| No SGIP Generator | 123MWh | N/A | N/A |
| Load Following ICE (3.8 MW) | 80 MWh | 50 MWh (55% of potential MWh) | N/A |
| Load Following ICE (3.2 MW)+ 15% PV | 82MWh | 40 MWh (52% of potential MWh) | 7 MWh (24% of potential MWh) |

Energy losses over the 24-hour period for different configurations are displayed in Figure 3-43.

**Figure 3-43: Losses over the 24-Hour Period on SCE C with Different Configurations**




The losses follow a similar profile over the 24-hour period for the two original cases of no DG operation on the feeder and 250 kW of added DG. As shown in Table 3-7, the change in losses from the scenario of no DG on the feeder to having the original 250 kW of DG added is approximately 1%. When the load-following 3.8 MW ICE replaces the original 250 kW ICE generator, the loss profile is a relatively straight line and is 49% less. Finally, combining 15% of the feeder peak demand as PV with a load following 3.2 MW generator results in a flat profile for losses and a 43% overall reduction in losses.

**Table 3-7: Average Losses and Percentage Change in Losses from No DG Option to DG Added Option for SCE C**

| Type of Operation | Average Loss (MW) | % Change from No DG |
|---|---|---|
| MW Losses: No DG | 0.133 | 0% |
| MW Losses: Original DG | 0.132 | -1% |
| Losses: Load Following 3.8 MW GEN | 0.068 | -49% |
| Losses: Non-Load Following 3.8 MW GEN | 0.116 | -13% |
| Losses: Load Following 3.2 MW DG + 15% PV | 0.076 | -43% |

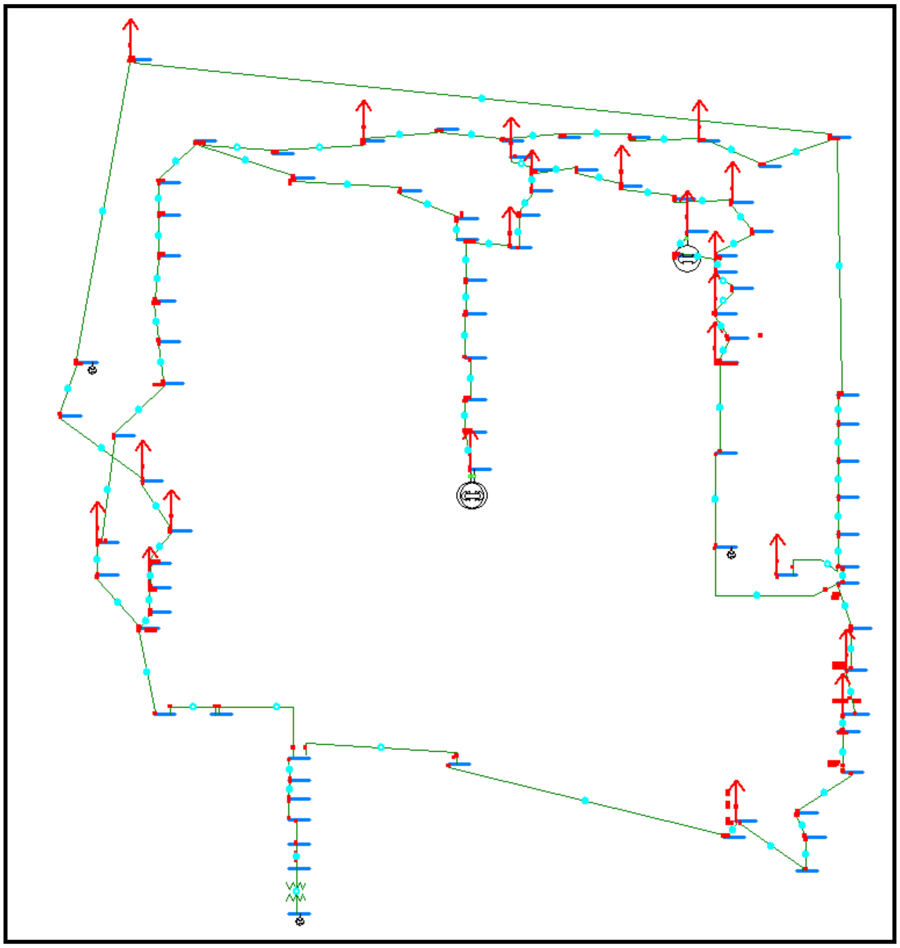
***SCE C Summary***

When a single ICE unit is used to provide load-following capacity, the ICE output is limited by its capacity on the distribution feeder (i.e., it simply lacks sufficient capacity to fully meet the peak demand of the feeder). The capacity limit is somewhat reduced when the ICE unit is combined with generation from PV system. The capacity limitation is further reduced by dispersing multiple ICE units on the feeder. Note that due to the late afternoon peak, the addition of PV does little to address the peak.

### *Modeling and Analysis of an SDG&E Feeder*

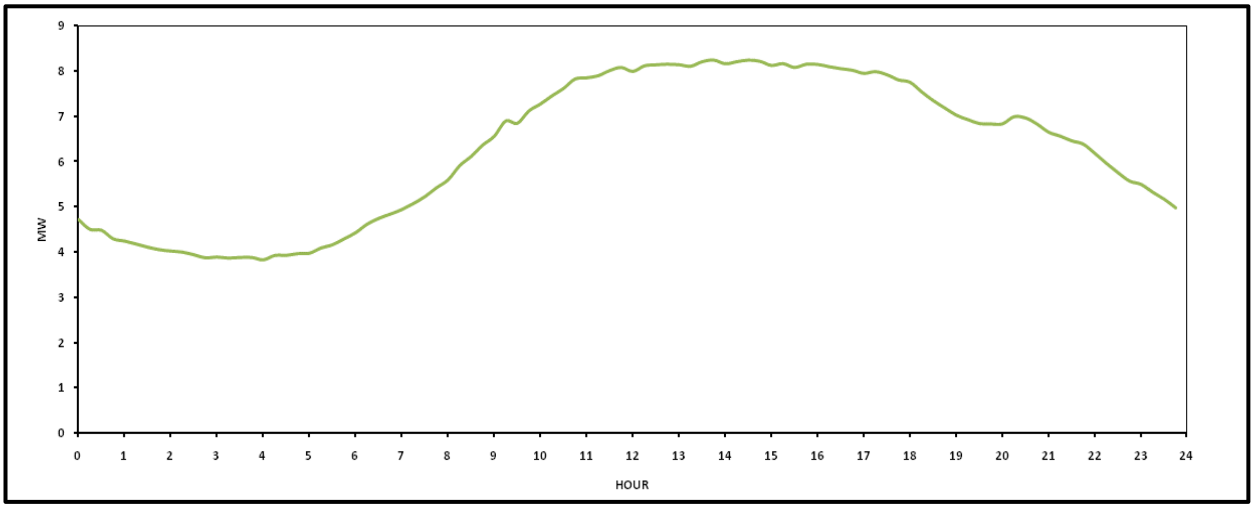
The feeder examined in the SDG&E service area is the SDG&E B feeder. There are three DG systems with metered data on the feeder. The total DG generation is 152 kW comprised of a 52 kW, 50 kW, and 49.8 kW PV systems. The DG PV generators are on substations with gen-tie line ratings of 2.2 MW to 2.4 MW. The San Diego service area is in Climate Zone 7. The feeder model contains 87 buses, 6 generators, and 21 loads. A one-line diagram of the modeled system is shown in Figure 3-44. The version described is an equivalence model that was created by deconstructing the output results from a model provided along with a printed one-line diagram of the SDG&E feeder model.

**Figure 3-44: Power World One-Line of SDG&E B**



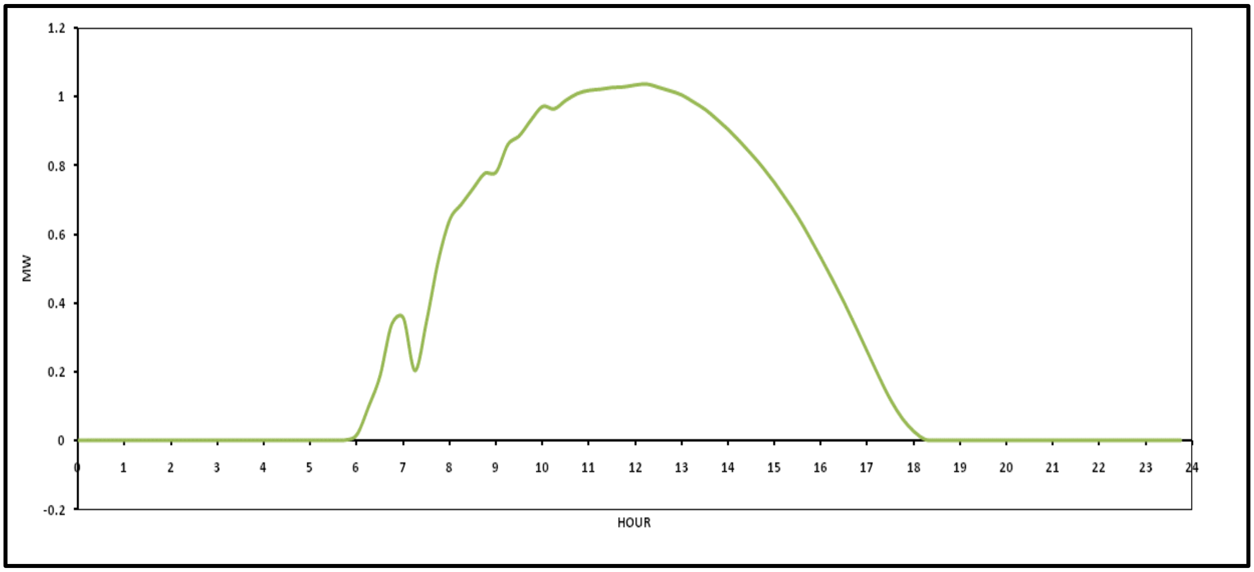
The peak demand of the feeder occurred on August 7, 2008 at a maximum load of 8.1 MW. The feeder demand shown in Figure 3-45 reflects demand at 100%.

**Figure 3-45: SDG&E B Feeder Demand Profiles**



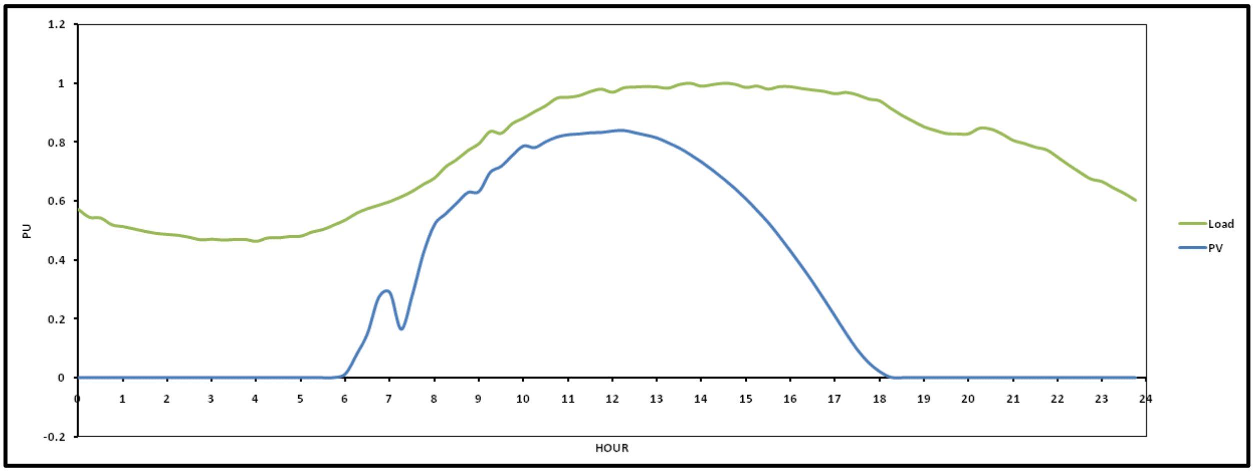
As with the previous feeder cases, SDG&E provided four months of data for the summer months from June to September 2008. No abnormalities were detected in the SDG&E B meter data. The generation profile of the PV units represent output of a typical PV generator, a bell curve with the peak energy production occurring in the afternoon hours. The generation profile is shown in Figure 3-46. The peak demand day occurred on August 7, 2008 and is the feeder profile used for this analysis.

**Figure 3-46: 152 kW SGIP PV Generation Profile**




As shown in Figure 3-45, the SDG&E B feeder peak demand spans across much of the afternoon from 12 P.M. to 4 P.M.. In comparison, the PV generation peak of 114 kW occurs at 12:15 P.M.. There is a dip in the PV generation from 8 A.M. to 11:30 A.M. but the cause is unknown.

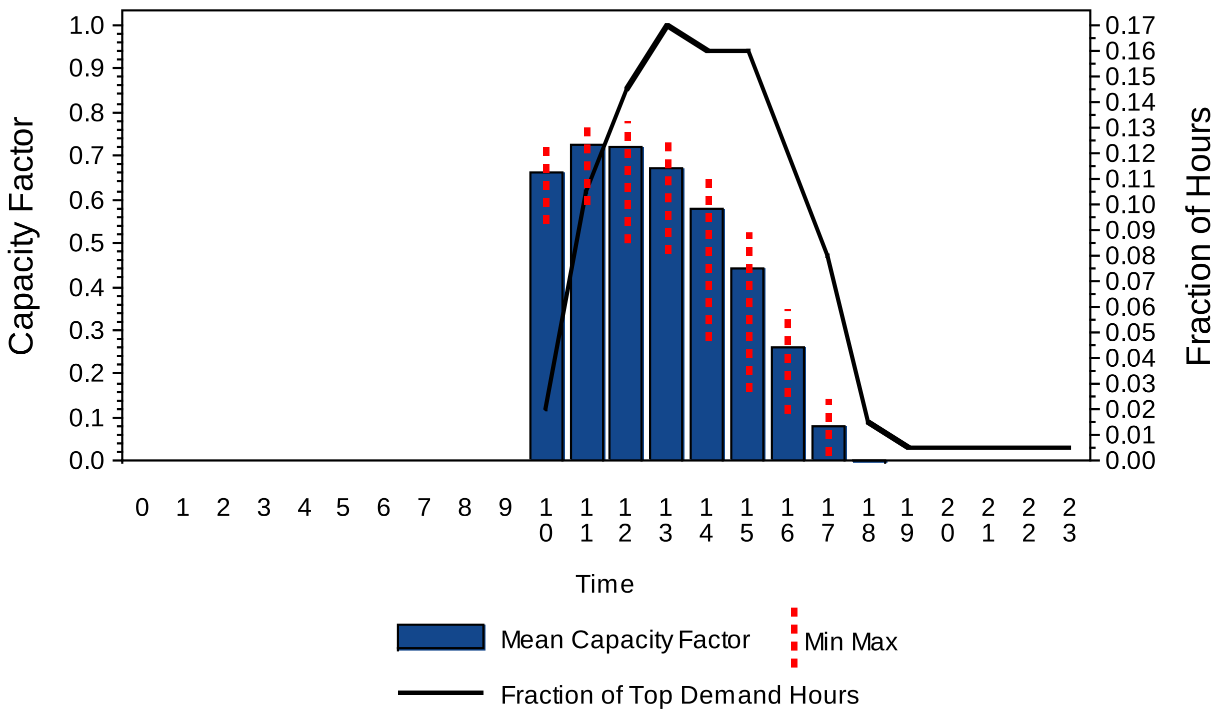
**Figure 3-47: Per Unit Representation of PV and Feeder Demand for SGD&E B**




The PV generation profiles and the feeder demand are graphed on a per unit basis for easy comparison in Figure 3-48. The DG generators are connected to distribution lines with ratings between 2.2 and 2.4 MVA. The line demanding should not exceed 100% of capacity in normal operating conditions. However, to simulate larger penetrations of SGIP generation, the existing PV generation was scaled and a second DG generator type with demand following capabilities was added to the feeder, diversifying the generation mix.

Figure 3-48 shows the mean and maximum and minimum capacity factors of the PV systems on the SDG&E B feeder during the top 200 hours of demand.

**Figure 3-48: DG Output During Top 200 Hours of Feeder Demand on SDG&E B**

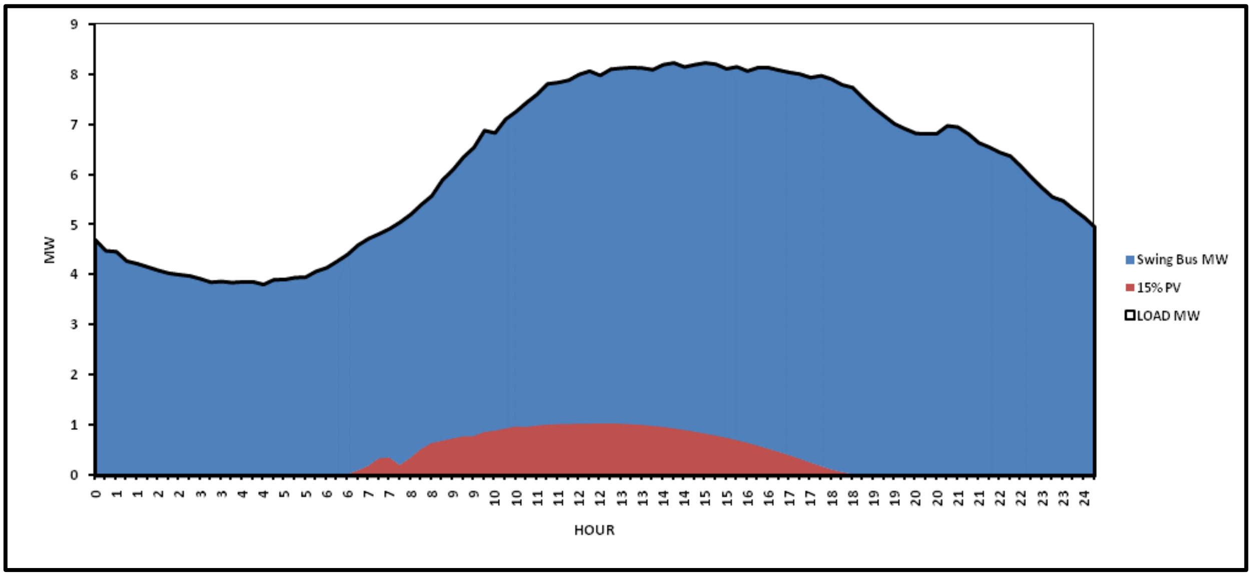



For the SDG&E B feeder, the second DG unit added to the feeder was a microturbine. The microturbine added to the SDG&E B feeder is based on the same assumptions and characteristics of the microturbine from the earlier PG&E B feeder analysis. The Swing Bus generator simulates the power that the connected utility provides to meet demand. When the MT follows changes in demand, the Swing Bus power is fixed. The PV and MT are scaled to higher penetrations so impacts from both resources can be determined.

***Task 1: Larger Penetration PV***

The initial PV penetration of 152 kW was increased to a total of 1.23 MW. The total PV contribution on the SDG&E B feeder at peak is 0.75 MW. Figure 3-49 displays the scaled PV and Swing Bus generation.

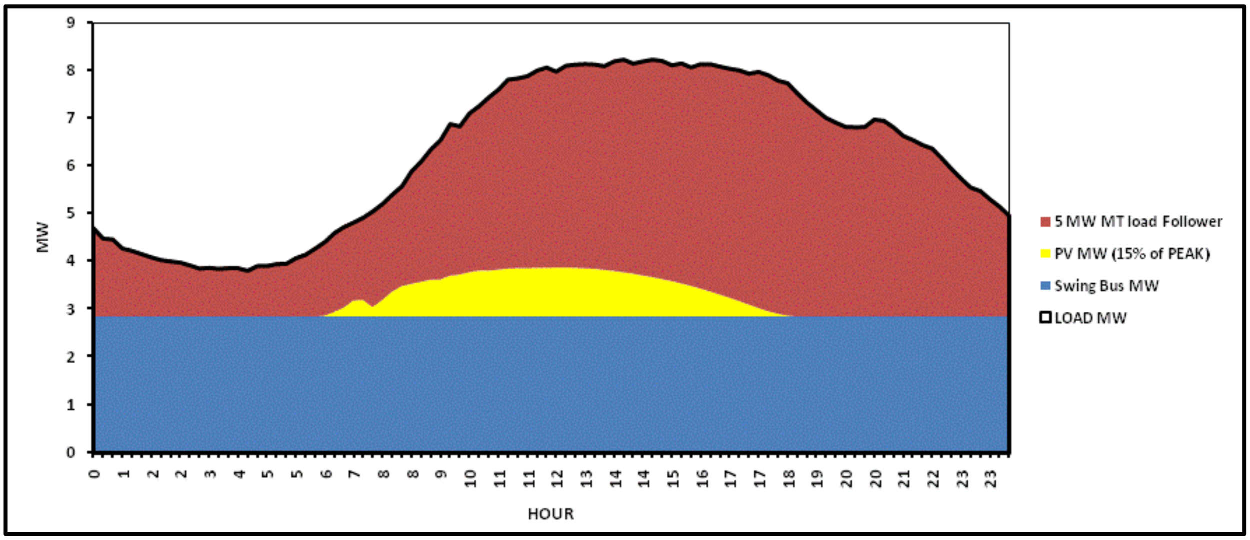
**Figure 3-49: SDG&E B PV Scaled to 1.3 MW**




## *Task 2: Diversify Generation Profile*

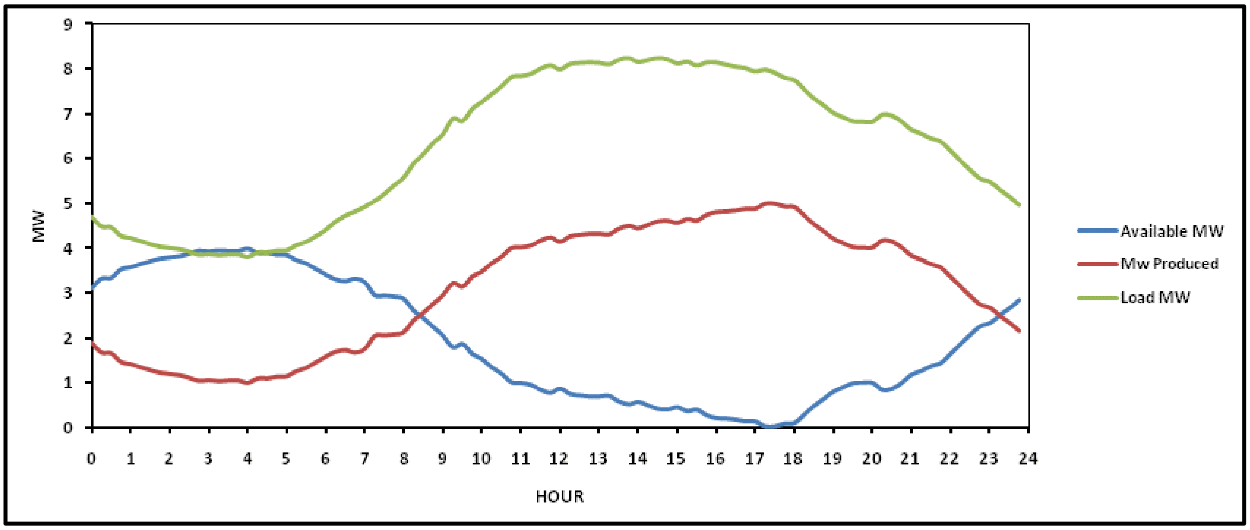
A good candidate to combine with the PV generation is a microturbine with demand following capabilities. Figure 3-50 shows an updated resource graph that includes the Swing Bus, PV, and the MT to meet demand over a 24-hour period. The black line is the demand profile. The blue area is the energy provided by the Swing Bus. The Swing Bus generation holds constant to demonstrate the MT load following capability (shown in the red area). The PV generation is shown in yellow.

**Figure 3-50: New Generation Profile with Fixed Swing Generation, Scaled PV, and MT Unit**



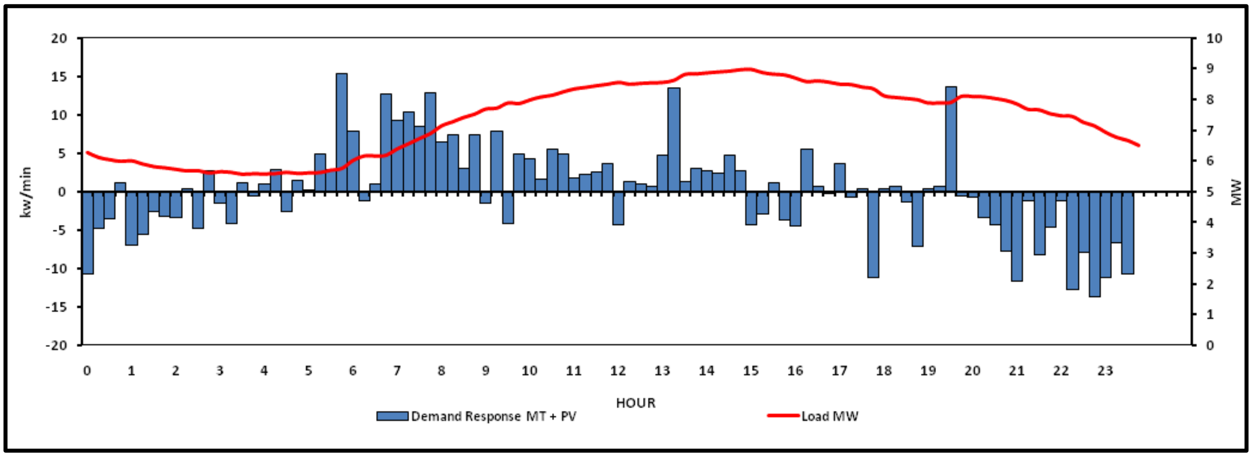
The size of the MT generator is 5 MW to meet the minimum and maximum load after the introduction of 15% PV. The minimum output of the MT is 20% of its maximum capability. The generator limits are defined in the original generator profile calculations. The 15-minute load and generation profiles are simulated over the 24-hour period. No additional overloads occur on the system and the bus voltages remain within normal limits. As shown in red in Figure 3-51, the 5 MW MT generation profile follows the feeder demand over a 24-hour period. The excess capacity is shown in blue and is the amount of capacity that the MT can contribute to load following.

**Figure 3-51: 5 MW Microturbine Generation and Excess Capacity**




Microturbines do not normally dispatch to load follow, but generate at a constant output. The ramp rate of the MT to follow load determines the capability of a MT to provide this service. The ramp rate calculation is over 15 minute increments, as a kW/min and is the difference in power generation from one 15 min period to the next 15 min period divided by 15 minutes. The required ramp rate is shown below in Figure 3-52. The maximum ramp up and down rate in any 15 minute per period is approximately 25 kW/minute. This is on the limit of the observed ramping capabilities of an MT, but within the manufacturer's rated capabilities. A ramp rate of 25 kW/minute is well within observed and rated capabilities for an ICE. Use of the MT or ICE on this feeder depends on if the observed capabilities of the MT are realistic.

**Figure 3-52: Required Ramp Rate for 5 MW MT on SDG&E B**




Energy calculations were completed similar to previous feeder examples. Combining PV with a MT unit eliminates the Swing Bus generator's need to load follow and increases the MT capability to provide power during the peak and off-peak periods. The MT provides additional utility reserve capacity during the morning and less capacity during the afternoon to evening. The types of commercial customer demand profile may be the cause instead of the MT itself. The energy output in MWh for a few operating scenarios is shown in Figure 3-8 for the 24-hour period. In some cases, the different DG unit energy is also shown.

**Table 3-8: SDG&E B Energy Output Calculations**

| Scenario | Swing Gen MWh over 24 Hours | Microturbine MWh over 24 Hours | PV MWh over 24 Hours |
|---|---|---|---|
| No Generator | 144MWh | N/A | N/A |
| 5.5 MW MT Load Following | 64 MWh | 80 MWh (61% of Potential MWh) | N/A |
| 15% PV + 5 MW MT Load Following | 64 MWh | 72MWh (60% of Potential MWh) | 8 MWh (28% of Potential MWh if could operate over 24 hours, 66% if only include 10 daytime hours as potential) |

In the first row, with no SGIP generators operating on the feeder, the Swing Bus provides 144 MWh of energy to meet feeder demand. When the 5.5 MW of DG MT is operating, the Swing Bus contribution reduces to 64 MWh and the DG units produce 80 MWh of energy. The last scenario includes both types of DG units. Together, the PV and MT produce 80 MWh of energy to meet feeder demand and the Swing Bus provides the additional 64 MWh to meet demand.. The calculated losses over the 24-hour period are shown in Table 3-9 for the same three scenarios:

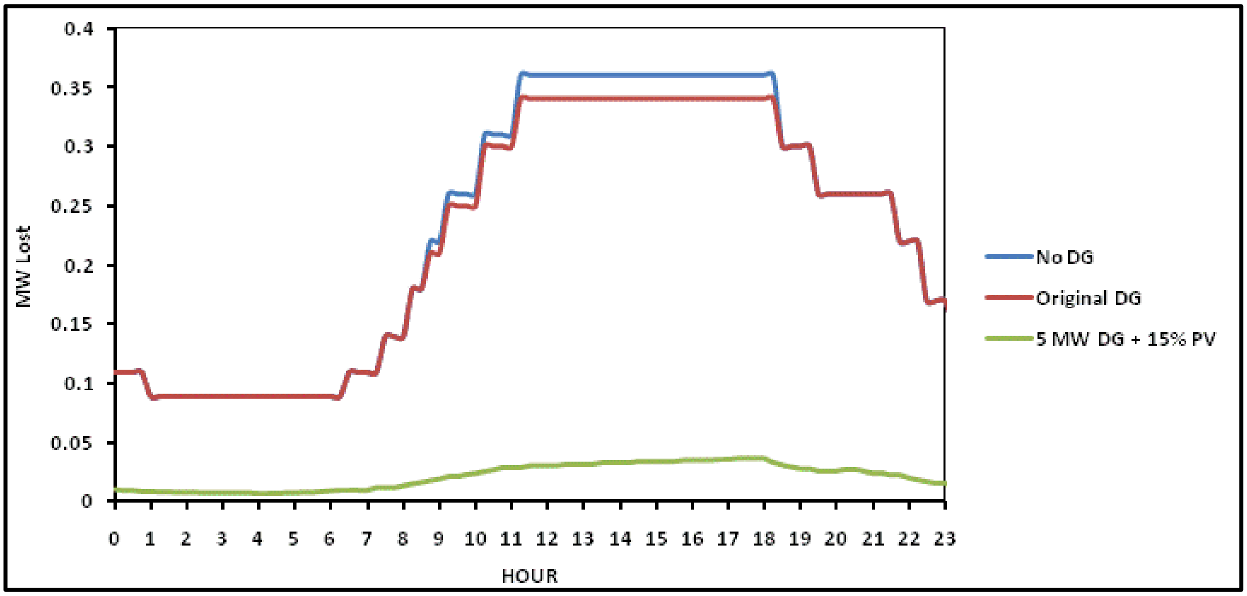
- No SGIP generation
- SGIP 3 MW PV unit
- SGIP 3 MW PV and 4 MW MT

**Table 3-9: SDG&E B Average MW Losses**

| Type of Operation | Average MW Loss | % Change From No SGIP Generator |
|---|---|---|
| MW Losses: No Gen | 0.229 | 100% |
| MW Losses: Original Gen | 0.222 | -3% |
| Losses: Load Following 5.5 MW GEN | 0.022 | -90% |
| Losses: Non-Load Following 5.5 MW GEN | 0.025 | -89% |
| Losses: Load Following 5 MW GEN + 15% PV | 0.021 | -91% |

Figure 3-53 depicts the hourly loss across the SDG&E B feeder for the 24-hour period. The losses between the No DG scenario and the Original PV scenario are similar except that the PV provides additional power during the daytime hours, resulting in a small (3%) reduction in losses. With the addition of the MT, the average MW losses on the feeder are reduced dramatically compared to the No DG scenario by 90%. The addition of a load following MT unit compares with the previous feeders and shows a significant improvement to the feeder demand when DG generators are located in the more heavy loaded areas on a feeder.

**Figure 3-53: SDG&E B Feeder Losses**




***SDG&E B Summary***

The SDG&E B feeder in SDG&E service area is located in climate zone 7. The peak demand of 8.1 MW occurs on August 7, 2008. The initial DG unit on the La Jolla feeder is a 152 kW PV. The PV unit is scaled to 1.3 MW to study the impact of larger DG generations. A 5 MW DG MT is combined with the existing PV and found to provide the MT the ability to load follow with some reserves for a call-for-power request from the utility..

### *Other Utility Feeders Included in the Study*

The other feeders included in the study are described in Appendix A. Because the analysis is similar to the three feeders discussed in detail above, we do not treat these feeders in the report. A description of the methods use for these other feeders is located in the appendix for review, as needed.

### *Aggregated Results: All Distribution Feeders and Generators*

One objective of this study was to develop a simple means for utility engineers and DG developers to identify the potential impacts of DG on different types and categories of distribution feeders. Such a tool could be a "look-up" table that identifies impacts of different DG technologies by different classifications of distribution feeders. Table 3-10 provides an aggregation of the original DG configurations on the analyzed feeders into a single table. The feeders are aggregated by utility, and identified as coastal or inland feeder. The average peak time for each feeder is identified as well as the makeup of the majority of customers serviced by the distribution feeder.

### Table 3-10: Relationships Between Original DG Systems on Analyzed Feeders

| Utility | Coast/ Inland | Average Peak Time | Majority Customers | Contribution Original ICE To Peak | % ICE Operating At Typical Peak Feeder Hour | Contribution Original PV To Peak | % PV Operating At Typical Peak Feeder Hour | Contribution Original MT To Peak | % MT Operating At Typical Peak Feeder Hour |
|---|---|---|---|---|---|---|---|---|---|
| PG&E | Coast | Mid-Afternoon | Residential/ Commercial | 0.6-2.0% | 54.8 - 81.7% | N/A | N/A | 3.1% | 86.4% |
| SCE | Coast | Noon | Residential | N/A | N/A | N/A | N/A | 9.2% | 41.6% |
| SCE | Inland | Late Afternoon | Residential | 0.5% | 12.8% | 0.0% | 0.0% | 0.2% | 18.4% |
| SDG&E | Coast | Mid-Afternoon | Residential/ Commercial | N/A | N/A | 0.8 - 2.0 % | 11.3 - 73.5% | 0.0% | 0.0% |
| SDG&E | Inland | Late Afternoon | Residential/ Commercial | N/A | N/A | 0.2% | 24.0% | 0.0% | 0.0% |
| PG&E | Inland | No Data | No Data | N/A | N/A | N/A | N/A | N/A | N/A |

For the analyzed distribution feeders, all of the feeder peaks occurred in the afternoon or evening. There were no morning demand peaks on the selected feeders. There was no coastal or inland PV included in this analysis for distribution feeders located within the PG&E service territory. For a PGE coastal feeder, the contribution of an ICE to peak demand was relatively small given the capacity of the generators, but in most cases, the generator was operating at over 50%, closer to 80% of its capacity. Coastal SCE feeders also had no PV data. The single ICE generator analyzed in this location was operating at approximately 42% of its capacity, but contributed 9% to the peak feeder demand. Inland SCE feeders had ICE, MT, and PV generation. Due to the late afternoon peak in this case, there is no contribution or operation of the PV during peak hours. The ICE and MT both operated at an average of 15% capacity, but provided under 1% of energy to the demand peak on the feeder. SDGE coastal feeders had a mid to late afternoon peak, and therefore the range of PV operation was from 11% to 74%. Although there was a MT analyzed, the actual output was 0% at the time of peak. SDGE inland feeders also had PV generation with negligible contribution to the peak, due to the late afternoon peak demand, operating at approximately 24%.

Overall, DG systems as currently deployed under the SGIP were found to have little impact on the feeder peak. Given the low penetration of DG on the distribution feeders, this result is not surprising.

Table 3-11 represents the aggregated results for blends of DG resources. As in Table 3-10, the results show the location of the feeder (i.e., coastal versus inland), customer mix, and average time of the feeder peak. The blended profiles fill more categories in each utility. We examined the same peak demand profile as with the Original DG, but now coupled it with load-following distributed MT and ICE generators. As expected with a load-following generator, the generator is operating at above 80% in most cases during peak hours. Although there is a dip in maximum output for microturbines in hot inland areas, both SCE and SDGE have a late afternoon peak. As a result, the actual temperatures were past the time where a reduction in performance would be expected to occur. Afternoon and mid-afternoon peaks also allowed PV to contribute much more to meeting the demand than if the peak occurred in the late afternoon or evening. In all cases, we assumed a contribution of PV equivalent to 15% of the feeder peak demand, independent of when the demand peak occurred. Therefore, the contribution of PV to peak demand varied from 4% to 13%. The highest contribution to peak demand was for the coastal PG&E feeders.

**Table 3-11: Relationships Between Blended DG Mixes and Analyzed Distribution Feeders**

| Utility | Coast/ Inland | Average Peak Time | Majority Customers | Contribution scaled ICE to peak | % ICE operating at typical peak feeder hour | Contribution scaled PV to peak | % PV operating at typical peak feeder hour | Contribution scaled MT to PEAK | % MT operating at typical peak feeder hour |
|---|---|---|---|---|---|---|---|---|---|
| PG&E | Coast | Mid-Afternoon | Residential/ Commercial | 34.3 - 74.9% | 96 - 100.0% | 8.0 - 12.6% | 52.1 - 61.0% | 37.3% | 83.6% |
| SCE | Coast | Noon | Residential | N/A | N/A | 9.0% | 60.8% | 44.6% | 99.0% |
| SCE | Inland | Late Afternoon | Residential | 42.5% | 94.2% | 1.4 - 9.2% | 9% - 21.0% | 81.8 - 86.0% | 95.1 - 100% |
| SDG&E | Coast | Mid-Afternoon | Residential/ Commercial | 26.9% | 71.0% | 4.3 - 11.4% | 11.3 - 75.7% | 54.4 - 64.4% | 85.9 - 89.8% |
| SDG&E | Inland | Late Afternoon | Residential/ Commercial | N/A | N/A | 6.70% | 24.0% | 49.7 - 72.7% | 91.3 - 95.6% |
| PG&E | Inland | No Data | No Data | N/A | N/A | N/A | N/A | N/A | N/A |

## 3.4 Optimizing Locations of DG Resources

Transmission Demanding Relief (TLR) Sensitivities are used measure the sensitivity of the flow on a contingency-overloaded device, such as a transmission line or transformer, to a transaction within California at the substation. The power flow simulator then determines the sensitivity of the flow on the monitored element to many different transactions involving the group specified as the source. To summarize, TLR sensitivities gauge the sensitivity of a single monitored element to many different power transfers.[5]

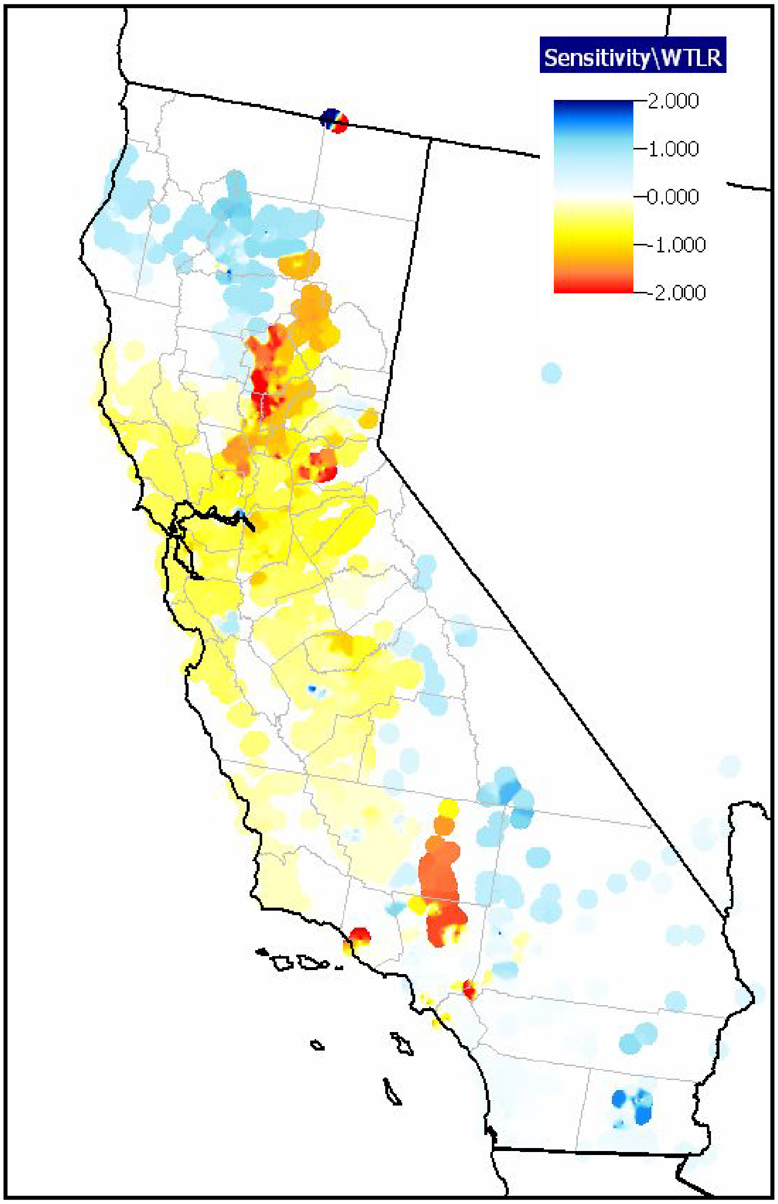
After an N-1 contingency analysis is completed, the TLR sensitivity computes the weighted transmission loading relief (WTLR) at transmission level buses (substations). The WTLR provides a quantitative measure of the locational value of injected DG to impact the reliability of the power system. Each bus in California is assigned a unique WTLR value, which allows the buses to be ranked according to their positive or negative impact on grid reliability. The bus WTLR represents the expected reduction of contingency overloads that would be achieved with one MW injection at that bus. Once the computation of WTLR sensitivities is completed, these values are contoured to obtain a spatial visualization of optimal locations in California for DG resources to be placed within a utility's service area. The WTLR values range from negative to positive values. Negative values are ideal locations that provide more benefit whereas positive values are poor locations that are congested. Optimal DG locations will be installed at buses with negative WTLR values, as these are locations that provide the greatest benefit to the electrical system.

### *2020 Summer Status—Base Case*

Utilizing the 2020 transmission demanding data set, an N-1 contingency was simulated in order to calculate the WTLR sensitivity values of the buses. The WTLR values are contoured on a map of California as shown in Figure 3-54.

5 Power World Simulator Manual – TLR Sensitivities

**Figure 3-54: 2020 Summer Base Case WTLR Map**

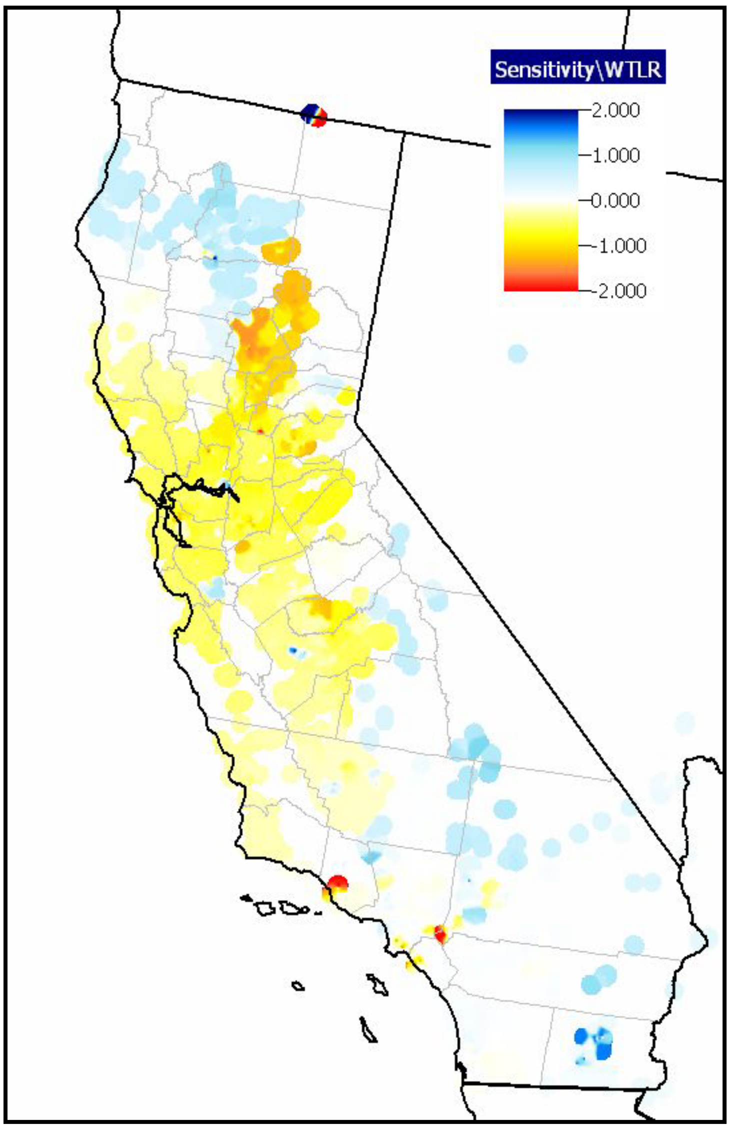



On the contour map of the 2020 Summer base case, the blue shaded areas indicate poor areas in which to add DG resources. The substations and transmission lines in those areas are nearing their thermal limits and additional DG resources may cause further stress on the electrical system. White areas on the map signify that it is a neutral area. Yellow to red-shaded circle indicate areas that will benefit from additional DG resources.

The buses are sorted by their WTLR values from lowest (negative values and beneficial impact) to highest (positive values and detrimental impact). This sorted list displays the priority of the locations that are ideal for new DG resources that will provide a benefit to the electrical grid. To verify this, the top 200 buses that had the lowest WTLR values were selected to have DG installed. The WTLR values of each bus are different; therefore, the DG capacity at each bus is sized accordingly. For example, a DG unit at a bus with a WTLR value of -6.3 is designated with greater capacity than a DG unit located at a bus with a WTLR value of -2.6.

Using this ratio methodology, 500 MW of assumed DG capacity was distributed across the top 200 buses. An N-1 contingency analysis was performed and new bus WTLR values calculated. These new WTLR values are contoured in Figure 3-55 to demonstrate the congestion reduction as the DG is added into areas that can benefit from additional DG resources.

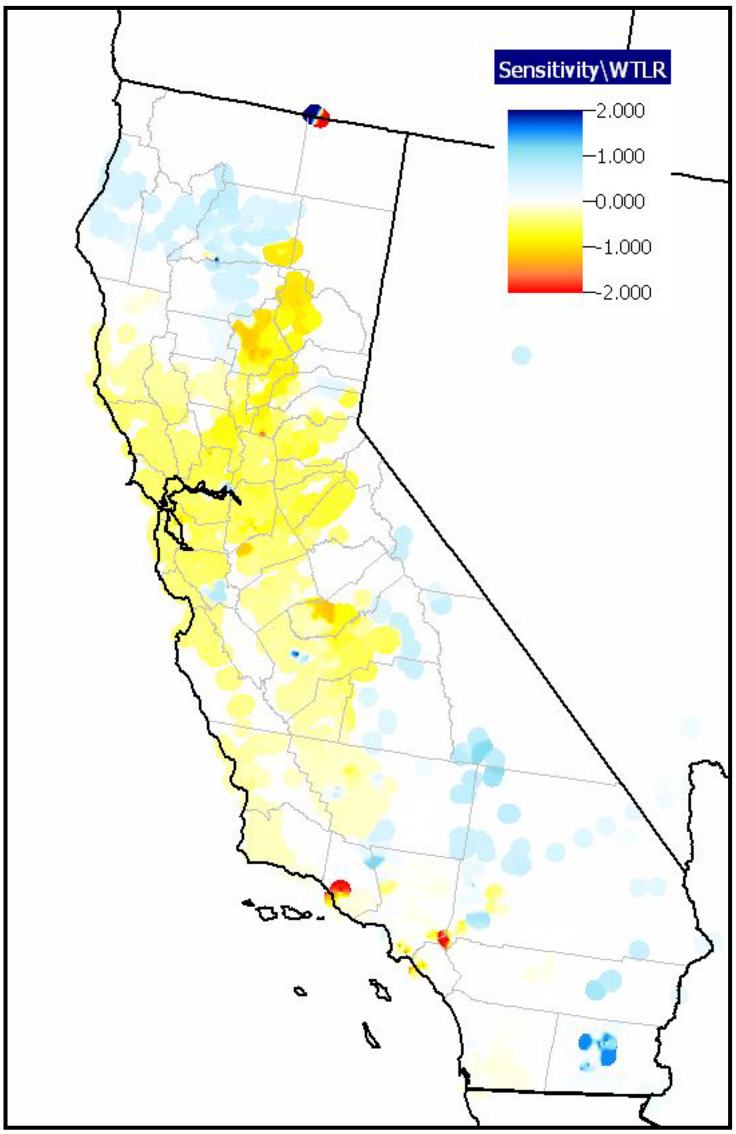
**Figure 3-55: 2020 Summer Base Case with 500 MW of DG**



The 500 MW of DG reduces the red shaded areas for Plumas, Butte, and Sutter counties in northern California and dramatically reduces the red areas near Kern and Los Angeles counties in southern California.

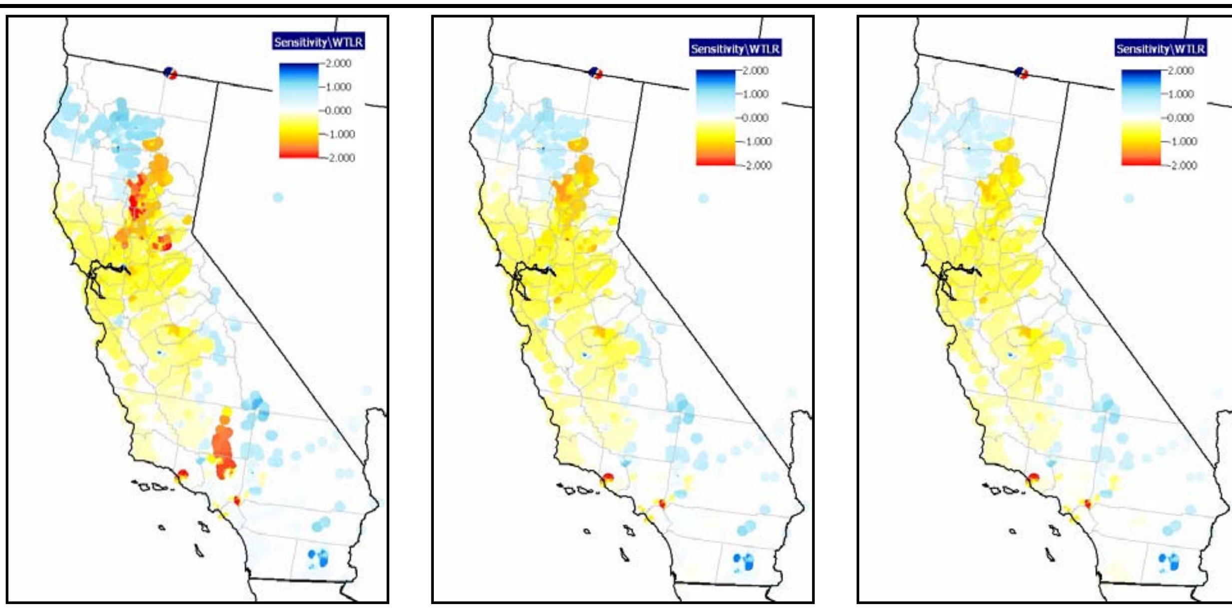
If the DG capacity is increased to 1,000 MW and distributed over the top 200 bus locations, the incremental benefit for this scenario is not substantial. Figure 3-56 shows the benefit of increased DG penetration on the top 200 buses. The area that receives the most benefit from the increased penetration is located up in northern California. These are the same counties affected from the scenario with 500 MW. There is negligible benefit in other areas from the increased DG capacity in this scenario.

**Figure 3-56: 2020 Summer Base Case with 1,000 MW of DG**



The progression of WTLR values on the base case, 500 MW of DG case, and 1,000 MW of DG case is shown below in Figure 3-57. The largest difference to the reliability of the system occurs with the increase in DG penetration from the base case to 500 MW of DG. This indicates the most optimal location for DG resources. When the penetration of DG is increased from 500 MW to 1,000 MW at the same 200 locations, the benefit is minimal. DG resources at smaller capacities distributed at more locations are more beneficial than DG resources at larger capacities distributed at fewer locations. Once the optimal location for DG is identified, the benefit of increased DG presence in those counties with the lowest WTLR values is a reduction in thermal demanding during a contingency outage.

**Figure 3-57: WTLR Comparison Between Base Case and Different DG Penetrations**




**Base Case** | **500 MW of DG** | **1,000 MW of DG**

Table 3-12 provides a breakdown of the amount of installed DG capacity at each particular county associated with the top 200 WTLR values. The top 200 optimal bus locations are in PG&E and SDG&E only. Each of the counties has an associated climate zone. There is a total of approximately 310 MW of DG in PG&E's area and 190 MW of DG in SCE's area for a total of 500 MW of installed DG at the optimal locations identified by the power flow model.

**Table 3-12: Installed DG Capacity per County for Top 200 Optimal Locations**

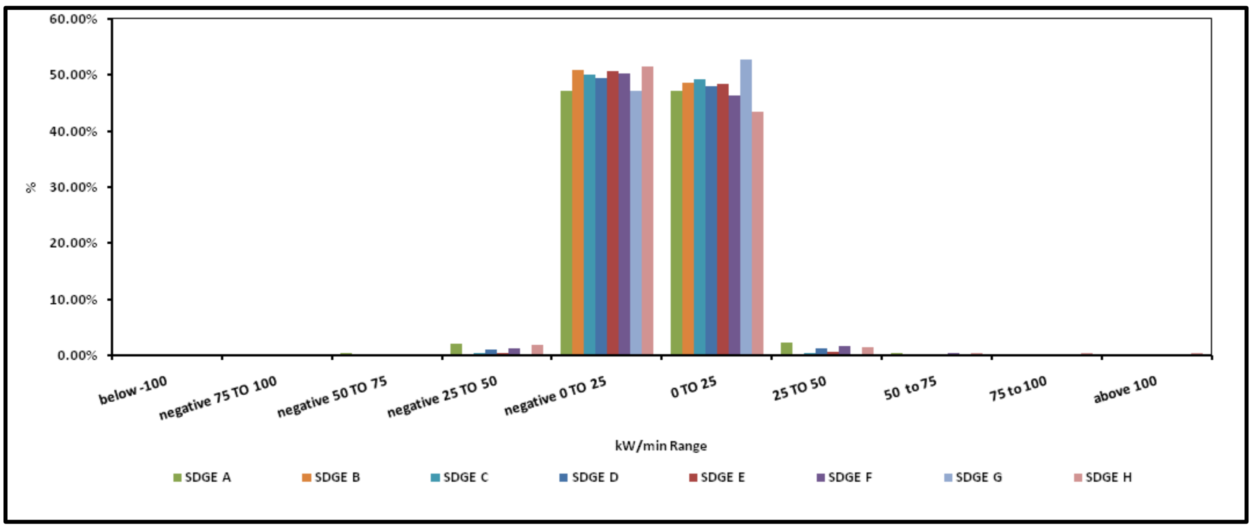
| Utility | County | Climate Zone | Installed DG Capacity (MW) |
|---|---|---|---|
| PG&E | Alameda | 4 | 3.9 |
| | Butte | 11 | 125.0 |
| | El Dorado | 12 | 26.7 |
| | Modoc | 16 | 5.9 |
| | Placer | 11 | 12.5 |
| | Plumas | 16 | 5.7 |
| | San Joaquin | 12 | 2.5 |
| | Solano | 2 | 2.6 |
| | | 12 | 8.0 |
| | Sutter | 11 | 72.8 |
| | Yolo | 11 | 11.6 |
| | | 12 | 13.8 |
| | Yuba | 11 | 19.2 |
| SCE | Kern | 4 | 87.7 |
| | | 13 | 21.6 |
| | | 14 | 4.2 |
| | | 16 | 2.0 |
| | Los Angeles | 9 | 5.3 |
| | | 14 | 33.0 |
| | Orange | 6 | 5.4 |
| | San Bernardino | 9 | 10.6 |
| | San Joaquin | 12 | 2.0 |
| | Ventura | 6 | 18.0 |
| | | **TOTAL** | **500.0** |

## 3.5 Conclusions and Recommendations

### *Demand Response Requirements*

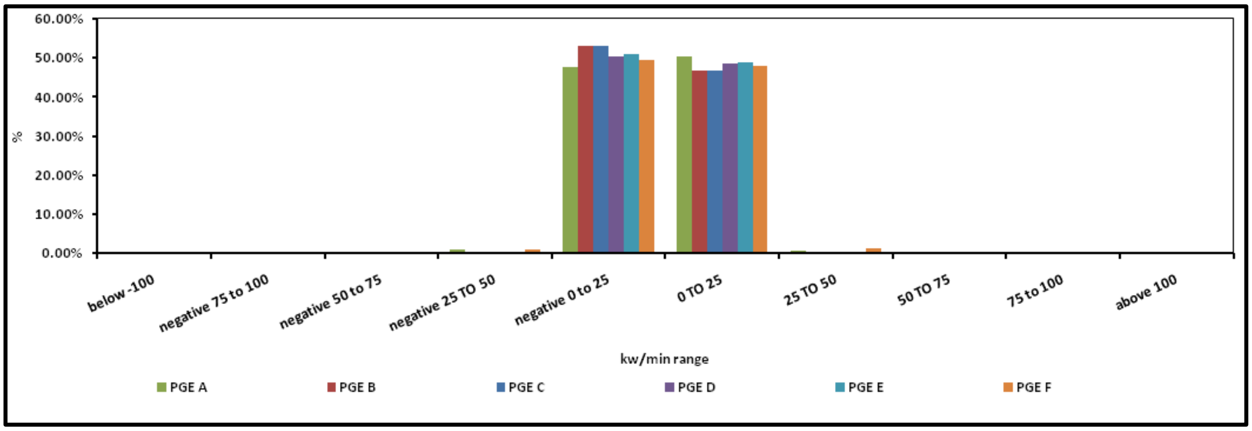
The analysis for individual feeders enables conclusions on the MW capacity required to meet demand on a feeder, and the individual feeders demand response requirements. The demand response requirements were analyzed using 15-minute demand data provided for all modeled feeders over the four (4) month Summer period. While higher fidelity data is more accurate, PG&E and SDG&E provided 15-minute demand data, adequate for this statistical analysis. Hourly data is not high enough frequency to obtain a valid result. The demand response for every feeder was calculated and sorted into ranges for each feeder. Rate numbers were then sorted into ranges of over 100 kW/min, 75 to 100 kW/min, 25 to 50 kW/min, and 0 to 25 kW/min, up and down (positive and negative). In SDG&E and PG&E the distribution of demand response values in each range was found to be very similar. As shown in Figure 3-58, on average 52% of the demand response points in the SDG&E cases are in the 0 to 25 kW/min range, and 44% are in the 0 to -25 kW/min range. The next highest percentage category is 25 to 50 kW/min with 2% of the data set, followed by -25 to -50 kW/min with 1.4% of the distribution. The other categories make up the remaining 0.6% of the 15 minute time periods, meaning at most the requirement for this demand response occurs in seven (7), 15 minute periods in four months, less than two hours.

**Figure 3-58: SDG&E Demand Response Rate Distribution**



PG&E cases were similar to SDG&E with respect to demand response rate distribution. The results were sorted in an identical manner. The rate distribution is shown in Figure 3-59.

**Figure 3-59: PG&E Demand Response Rate Distribution**



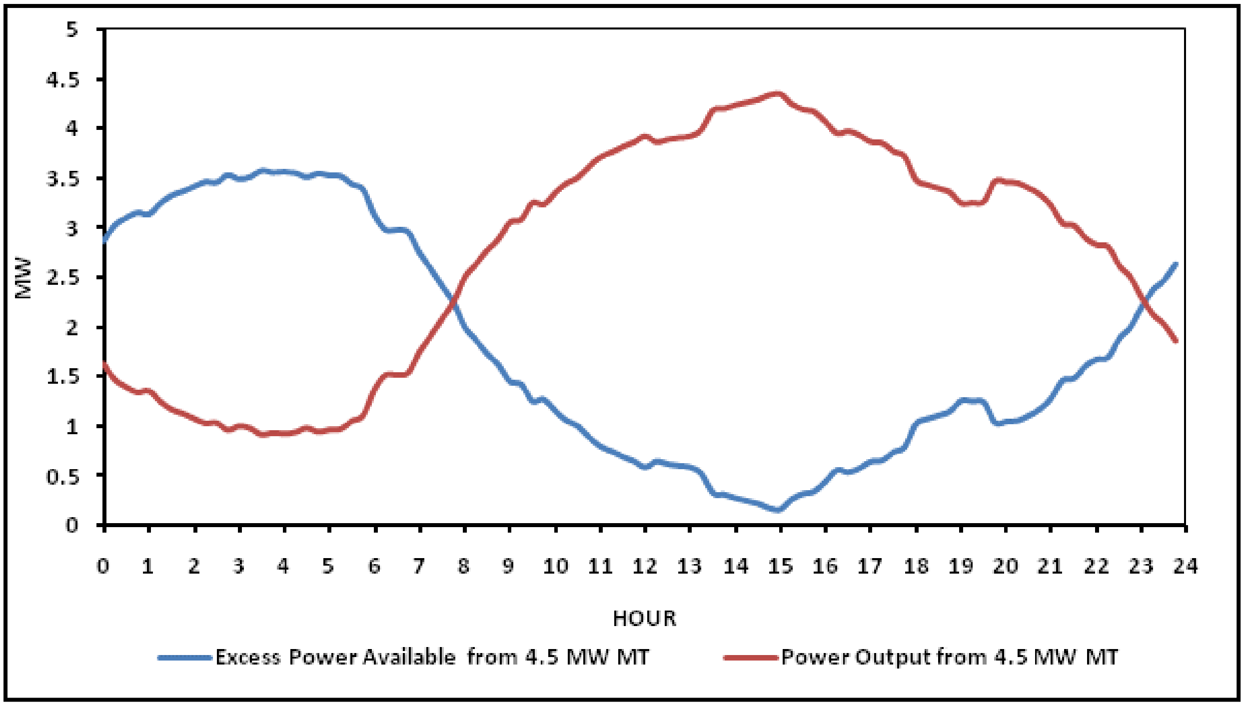

In PG&E's rate response distribution, 98% of the demand response rates were between -25 and 25 kW/minute. Approximately 2% is distributed above/below these levels.

Analysis of the distribution rate shows that there is only a small percentage of time a generator is required to provide power at a rate above 25 kW/minute. The type of generator required is therefore more flexible and varied. The data is averaged over a 15 minute period. With data above this fidelity, higher demand response requirements may be identified. The trade-off between higher demand response and cost must be considered for using faster ramping generators.

### *Call for Power and Generator Optimization*

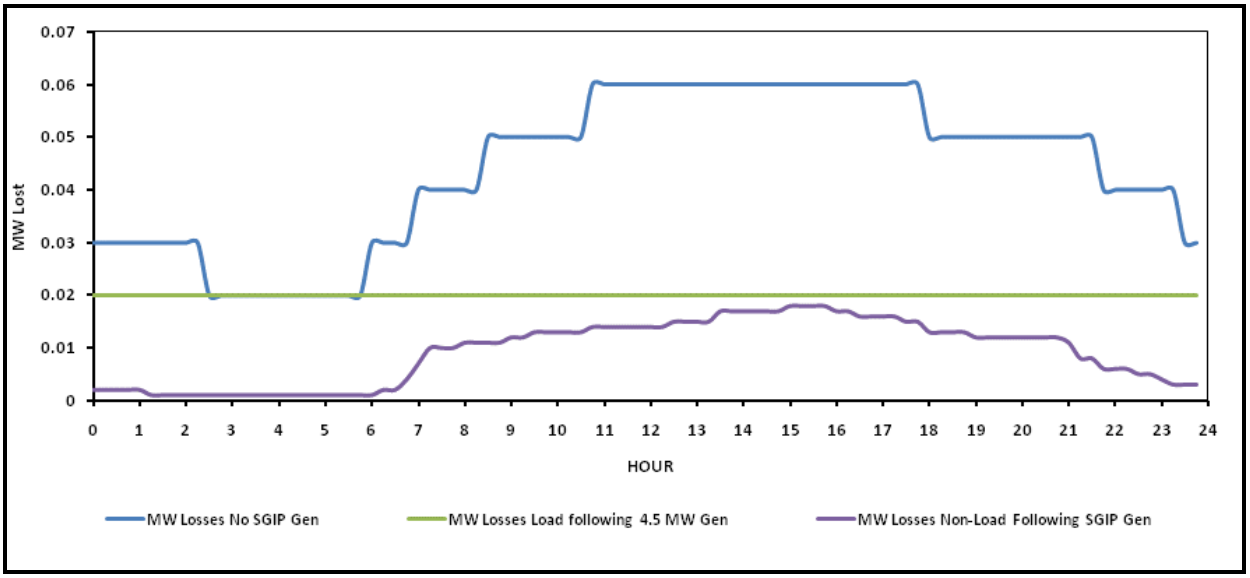
Using a demand-following generator makes excess power available for utility reserve capacity. Figure 3-60 shows the power available for one generator operating in a load-following configuration.

**Figure 3-60: Call for Power for an Off-Peak Generator Plus Available Power from the Generator**



When operating in a load-following configuration, the maximum amount of power is not provided by the generator at all times, and optimal efficiency operation is not achieved. Operating the generator at a constant power output means there is little power available for a call-for power situation, but the efficiency of the generator is improved, and maximum power can be delivered onto the feeder. Maximum power delivered means the substation provides less power, and the MW line losses are reduced on the system. Figure 3-61 shows the line losses plotted over a 24-hour period. The losses overall are lowest in the case where the generator acts as base-loaded at 80%.

**Figure 3-61: Losses are Minimized on the Feeder when Operating as a Non-Demand Following Generator**



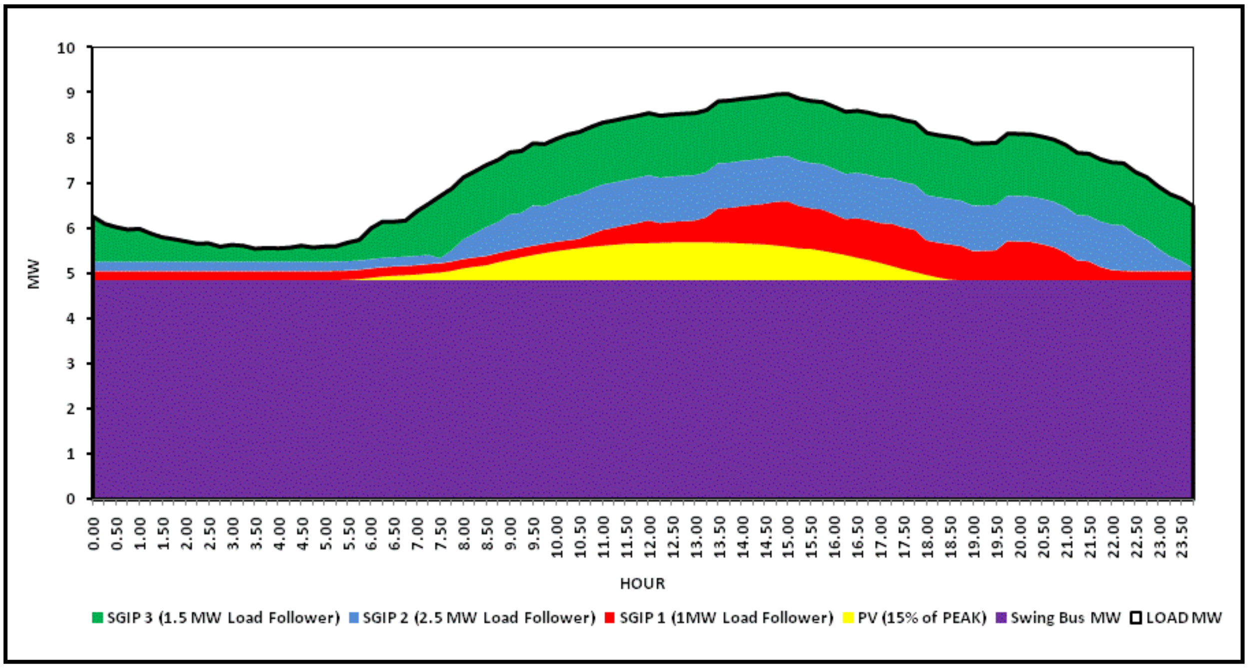

Optimizing the dispatch of the DG resource is a balancing act of operating in such a way that customer demand is met, but also so a call for power can be satisfied. An ideally operating DG system can reduce feeder and substation losses, while providing ancillary services to the utility.

DG feeders can be classified based on location, timing of peak and customer mix. Distinctions are made for distribution feeders based on these classifications. Inland and coastal feeders tend to peak at different times. Distribution feeders with mainly residential and commercial customer mixed tend to show smoother peaks, while industrial distribution feeders tend to show faster and more frequent ramping of peak demands. Ramp rate requirements are dependent on the facility being served but tend to fall between the -25 to 25 kW/minute range requirement.

***Comparison of Dispersed Generation and PV Penetrations***

While a benefit of adding generation to the distribution feeder is loss reduction, the loss reduction is also influenced by the installed generation magnitude, the type, and its distribution on the feeder. The effect of these different conditions is quantified by calculating the loss reduction per MW of DG dispatched. In PG&E B, a large penetration of PV was initially assumed and the largest generator that could be supported by the distribution lines closest to its location. The amount of PV is reduced to 15% of peak (1.4 MW). The MT capacity (4 MW) is dispersed across the feeder. The new generation blend is shown in Figure 3-62.

**Figure 3-62: New Generation Blend for PG&E B**



Running a time step analysis for only this amount of PV results in losses reduction of 24 kW per MW of PV installed. Installing 85% PV results in a loss reduction of 1.85 kW per MW. The kW of losses reduced per MW is expected to be constant, but varies as a function of how the circuit is loaded with the new generation. An increase in loading in specific areas due to reverse power flows could result in a smaller loss reduction with more MW of DG dispatched. Dispersing the larger DG units on the feeder also results in lower losses. A combination of 15% PV and dispersed MT provides optimal loss reduction. Energy losses associated with dispersing the generation are shown in Table 3-13. With 5.34 MW installed, losses are reduced by 7 kW per MW.

**Table 3-13: Loss Reduction on Feeders by Dispersing Generation**

| Configuration | MW | Average Losses | Difference | Losses Reduced kW per MW Installed |
|---|---|---|---|---|
| Demand Following | 4 | 0.0069 | 0.0370 | 9.3 |
| 80% SGIP | 4 | 0.0064 | 0.0376 | 9.4 |
| 80% SGIP + 15% PV | 5.34 | 0.0057 | 0.0382 | 7.2 |
| PV only 15% | 1.34 | 0.0112 | 0.0328 | 24.5 |
| 15% PV + Demand Following 3.5 MW | 5.34 | 0.0063 | 0.0376 | 7.0 |

# 4

# Data Sources

Representative data are selected from metered generation data for DG systems deployed under the SGIP, coupled with metered demand data from facilities housing the SGIP generation systems, and metered demand data for the distribution feeders that interconnect the SGIP generators to the electricity system. For the purposes of this study, we used a sample of generation, facility demand, and distribution feeder load data from calendar year 2008. We limited the evaluation to the four summer months of June, July, August, and September of 2008 as the focus of the evaluation was on addressing peak electricity demand.[1]

SGIP generation systems are selected to represent a cross section of DG technologies and capacities; IOU service territory; and climate zones. In turn, distribution feeder data are obtained for selected distribution feeders based on a cross section of IOU service territory, customer mix, climate zone, and time of feeder peak (e.g., early afternoon, late evening, etc.). Metered demand data for facilities housing SGIP generation systems were selected to represent a cross section of DG technologies, IOU service territory,[2] climate zone, and type of customer application.

1 While some customers and distribution feeders may have peak demand occurring outside of the summer, a significant amount of peak demand in California occurs in the summer.

2 Only PG&E was able to supply electricity demand data for facilities housing SGIP generation systems.

Table 4-1 summarizes the metered data available for the study. In general, there is a good cross section of metered generation data and distribution feeder load data. However, only PG&E was able to provide electricity demand data for facilities housing SGIP generators.

**Table 4-1: Summary of Data Provided for Study**

| Data Type | PG&E | SCE | SDG&E |
|---|---|---|---|
| DG Generation | Provided via SGIP metered data sets | | |
| PV | | | |
| ICE | | | |
| MT | | | |
| GT | | | |
| FC | | | |
| Feeder Demand (Load) | | | |
| Climate Zone | Yes | Yes | Yes |
| Customer Mix | Yes | Yes | Yes |
| Time of Peak | Yes | Yes | Yes |
| Customer Electricity Demand | | | |
| Climate Zone | Yes | N/A | N/A |
| Application (NAICS) | Yes | N/A | N/A |

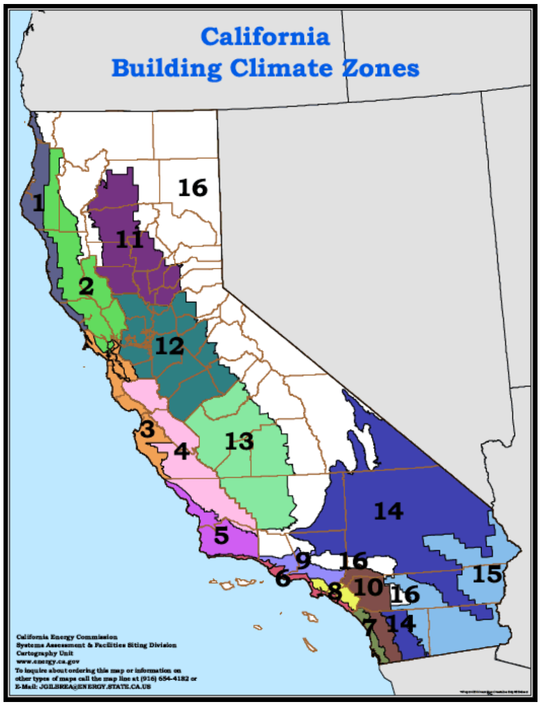
N/A: Data were not provided

## 4.1 Selection of Representative Distribution Feeders

Representative distribution feeders were selected for each IOU based on the type of DG technology, climate zone, and customer mix on the feeder. The feeder selection was limited to those distribution feeders that were interconnected DG systems with historical 15-minute interval generation data and for which the IOUs had corresponding 15-minute feeder demand data.

A cross section of distribution feeders was based on climate zones. The CEC has developed 16 designated building climate zones ranging from coastal, valley, desert, and mountain climates. Figure 4-1 is a map of California's 16 building climate zones.

**Figure 4-1: California Building Climate Zones**




The location of DG technologies into different climate zone can affect the generation profile of the DG system due to local weather conditions (e.g., ambient temperatures, cloudiness, rainfall, etc.). For example, microturbines located in hot desert climate zones may show de-rating during the highest daytime temperatures due to their sensitivity to ambient air temperatures. Similarly, PV generation profiles can be affected by fog and cloudy conditions associated with coastal climate zones.

As part of the feeder selection process, the IOUs were provided with a list of SGIP generators for which there was complete 15-minute interval generation data for 2008. The IOUs determined the feeder that served the facility and the availability of historical feeder load data. Each IOU was asked to select 10 feeders for which they could provide information. For each feeder, four months of 15-minute feeder demand data were requested for the months from June through September of 2008. In addition, the IOUs were requested to provide the feeder customer mix (residential, commercial, industrial) along with the feeder one-line diagram, line characteristics, and GIS data. During the course of the feeder selection process, the IOUs discovered missing or unavailable data for some of the 10 feeders. As a result, the actual number of feeders for which the IOUs could provide data was reduced to six (6) feeders for PG&E, six (6) feeders for SCE, and five (5) feeders for SDG&E.

Table 4-2 summarizes the distribution feeders for which the IOUs could supply feeder demand data, along with the associated customer mix and climate zone. Table 4-2 also shows the type of SGIP generator types interconnected to the electricity system via the selected feeders.

**Table 4-2: Examined Distribution Feeders and Feeder Characteristics**

| Utility | Feeder | Climate Zone | Commercial Load | Industrial Load | Residential Load | SGIP Generator Type |
|---|---|---|---|---|---|---|
| PG&E | Mt Eden | 3 | 11% | 2% | 82% | 3-PV; 1 ICE |
| | Britton D1115 | 3 | 54% | 38% | 7% | 1-PV |
| | Weber D1113 | 3 | 11% | 2% | 87% | 1-ICE |
| SCE | Allergan | 8 | 99% | 1% | 0% | 1-MT |
| | Coupler | 9 | 98% | 0% | 2% | 1-MT |
| | Lowry | 13 | 56% | 43% | 1% | 1-ICE |
| | Shirk | 13 | 94% | 6% | 1% | 1-PV |
| SDG&E | Jamacha | 7 | 57% | 16% | 27% | 3-PV |
| | La Jolla | 7 | 76% | 0% | 24% | 3-MT |
| | Kettner | 7 | 52% | 48% | 0% | 1-PV; 2-FC |

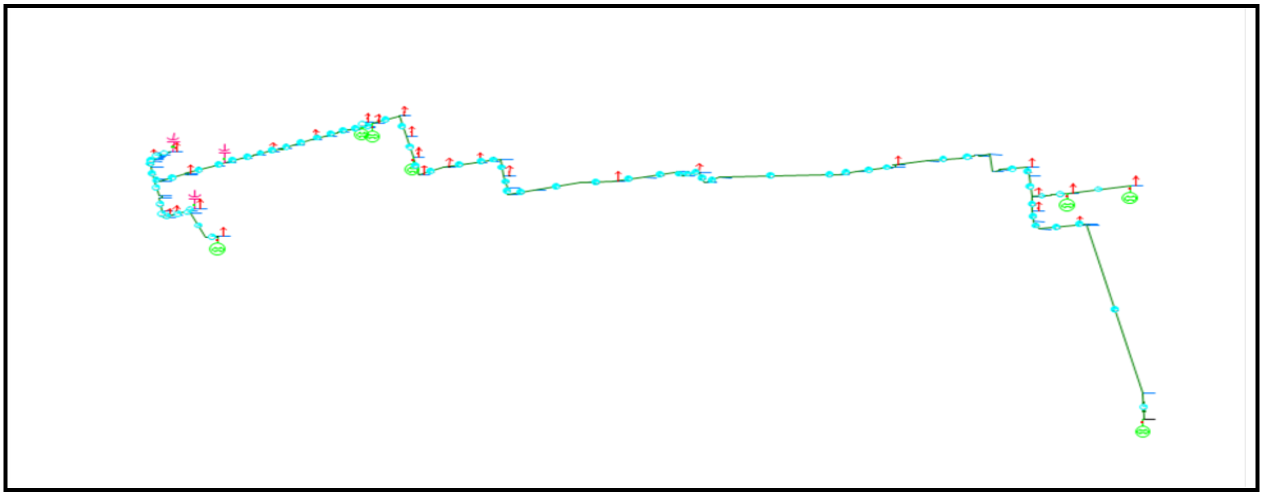
### *Development of Distribution Power Flow Data Sets*

Direct comparisons between DG generation profiles and feeder load do not by themselves indicate the possible impacts of increased DG on the feeder. Consequently, power flow simulations were used to examine how different quantities and types of DG may affect the distribution feeders. There were two simulation models considered for use in conducting this analysis: The SynerGEE distribution software and the Power World transmission software. The

Power World software was selected since the feeders are radial and the objectives do not include protection coordination, switching between feeders during emergencies and single-phase loads. In Power World, it is easier to simulate contingency conditions; ramp rates; and time sequential load and generation levels.

In order to protect confidentiality of feeder and generation data, all simulations were sanitized to remove references to location and feeder numbers. A sample sanitized feeder circuit is shown below in Figure 4-2. A feeder contains hundreds of single-phase and three-phase transformers of various sizes. The actual customer load served by each line transformer does not equal the transformer nameplate rating. Since the 15-minute load data points are simulated over a selected time period (such as one day, one week, or one month), the assignment of 15-minute load data to hundreds of transformers is too exhaustive. Interrupting and managing the data is very difficult.

**Figure 4-2: Sample Feeder Circuit**

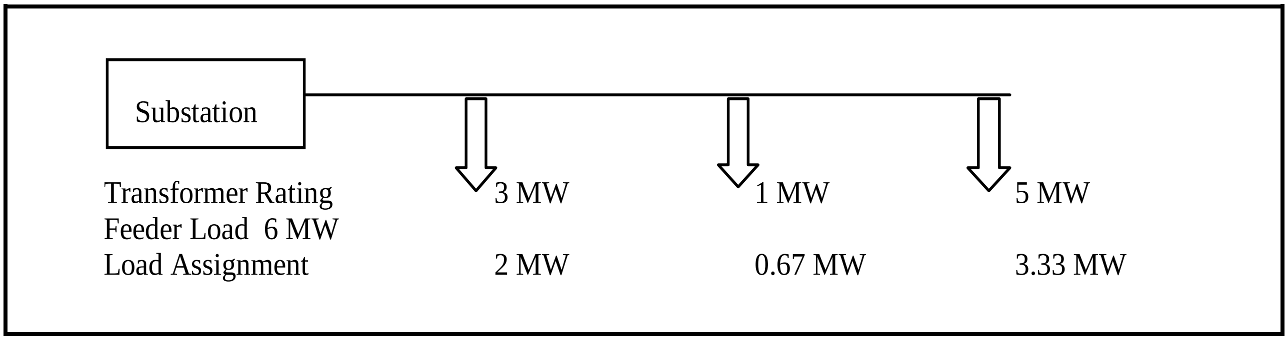


The transformer installed capacity from the utility one-line diagram aggregates into load pockets to reduce the number of transformers to a manageable number. Depending on the location of the DG system on the feeder, the feeder system beyond the DG location converts to an equivalent load. The capacitor banks located between the substation and the DG system remain in service at the rated values. If there are other DG generators on the feeder for which there is no metered generation data, the generators are modeled in the open position or non-generating position.

### *Treatment of Aggregated Feeders*

A load value is assigned to each aggregated transformer. The criteria used to assign load to each aggregated transformer prorates the load based on the ratio between the metered feeder load and the total transformer capacity. Figure 4-3 is an example of how an aggregated transformer is treated in the model.

**Figure 4-3: Example of Aggregated Transformer**



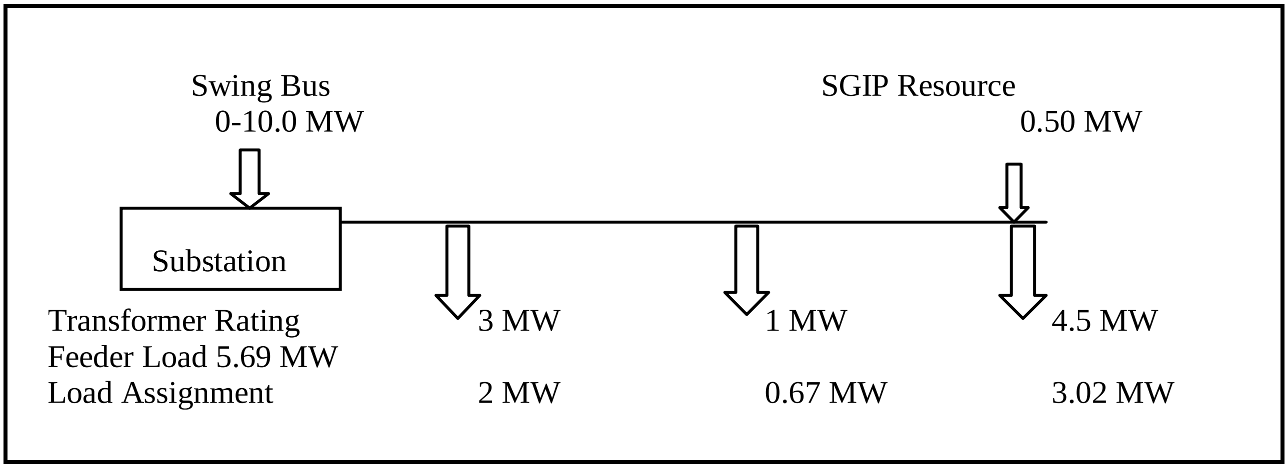

In this example, the total feeder load for this one hour is 6 MW but the total aggregated transformer capacity is 9 MW. The ratio of feeder load to transformer capacity is 0.67. Each transformer capacity is multiplied by the ratio to obtain the load assigned to each transformer. This prorating is required since the utility does not have the 15-minute loading on each individual transformer but only on the total feeder.

Since Power World simulates 12 kV feeders, there must be at least one generating resource called the “Swing Bus”. In a normal power flow data set that is significantly larger than a single feeder, the Swing Bus dispatches to serve all un-served load during contingency analyses. The Swing Bus generator is normally located remote from the utility system under study. If the Swing Bus is too close to the load centers, the Swing Bus could pick up more load and cause local transmission lines to overload.

Because each feeder is simulated with no interconnections to other feeders, the Swing Bus is located on the substation bus serving the feeder load. The generator size is larger than the summation of the feeder load and the DG resource. The one feeder now includes the Swing Bus and the DG resource. As new potential DG resources are added to the feeder, the dispatch between the Swing Bus and the DG resources becomes a little complicated. As contingency analysis is completed, the Swing Bus attempts to pick up the load because it is located on the feeder. The Swing Bus is adjusted such that the DG resources are the first to dispatch.

Figure 4-4 shows an example of the Swing Bus modeling.

**Figure 4-4: Example of Swing Bus Modeling**




The Swing Bus can operate from 0 to 10 MW, and there is a 0.5 MW PV installed on the feeder. The PV reduces the load from 4.5 MW to 3.02 MW. This reduces the demand that the Swing Bus must serve from 6.0 to 5.69 MW.

### *Transmission Loading Data Set*

The transmission loading data set begins with the PG&E 2017 WECC-approved and solved data set. Corrections are made to reflect both a 2020 peak load forecast and 2020 peak generation forecast to accommodate for the load increase. The Path flows are fixed at their maximum imports and exports for the summer transmission data set. The power flow model adjusts dispatchable resources such as natural gas, diesel, and coal automatically when DG resources are added in the system. The power flow model does not automatically control non-dispatchable resources such as hydro generation, geothermal, biomass, and existing renewable resources. These resources are operated at their respective designated output capacities and do not change when DG resources are added in the system. As new DG resources are added to the system, these are assumed to be non-dispatchable.

There is 2,850 MW of distributed solar PV included in this analysis derated to 58% of the maximum capacity, to represent the difference between the peak load period and peak solar generation. The coincidence factor is based on studies by the Energy Commission. The PV resources represent the California requirements for one million homes or 3,000 MW of residential PV by 2020.

# Appendix A

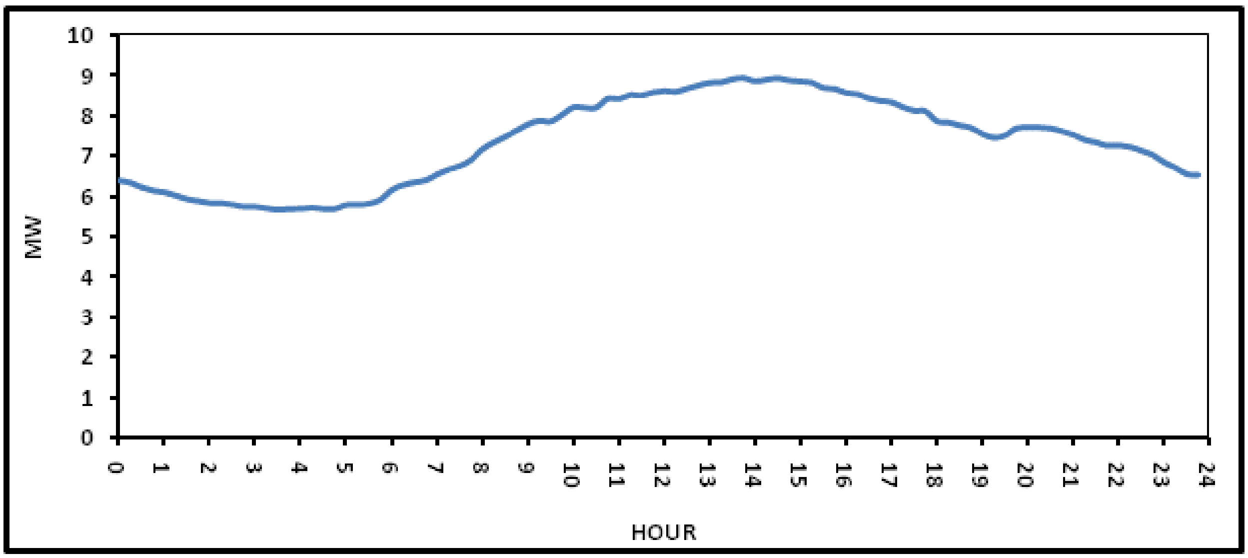
## Analyses of Additional Distribution Feeders Examined for the Study

### A.1 Summary of Other PG&E Feeders

***PG&E C***

Feeder PG&E C is located in Climate Zone 12. The load profile for PG&E C is very similar to PG&E B. The peak occurs on September 5, 2008 and is graphed in 15-minute increments in Figure A-1.

**Figure A-1: Load Profile for Feeder PG&E C**




Minimum load is 5.67 MW at 4 A.M.; maximum load is 8.95 at approximately 2 P.M.

The original generator profile data is not consistent across the time period as shown in Figure A-2. Because of this abnormal ICE dispatch, a more consistent ICE generating profile is used. More analysis is needed to determine why this occurs; however, this is outside of the scope of this project.

**Figure A-2: ICE Original DG Load Profile**

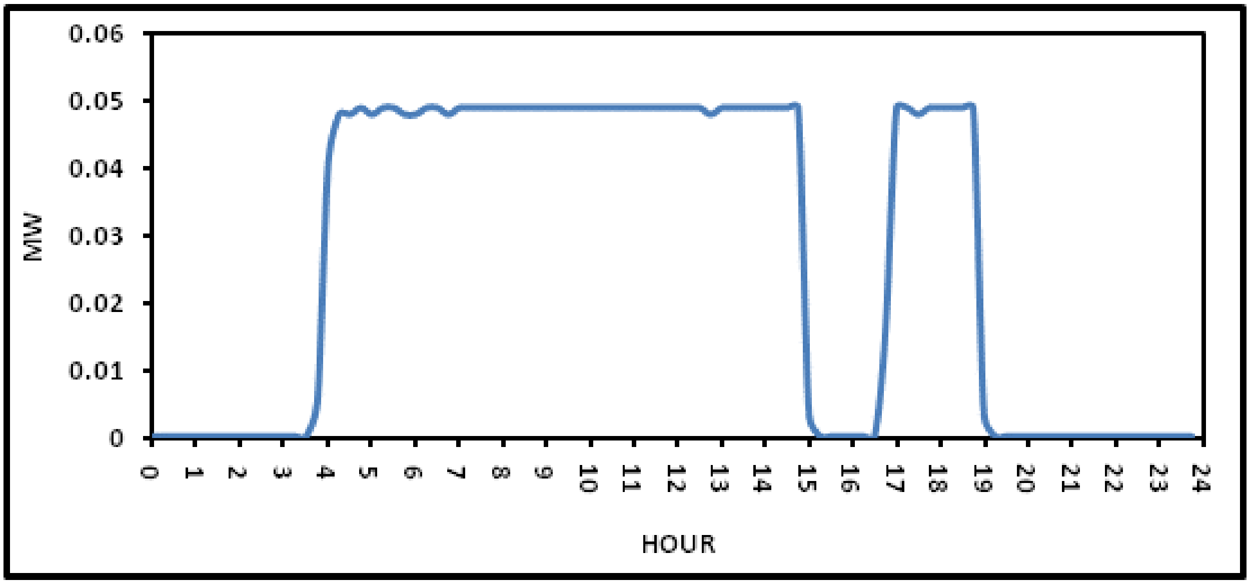
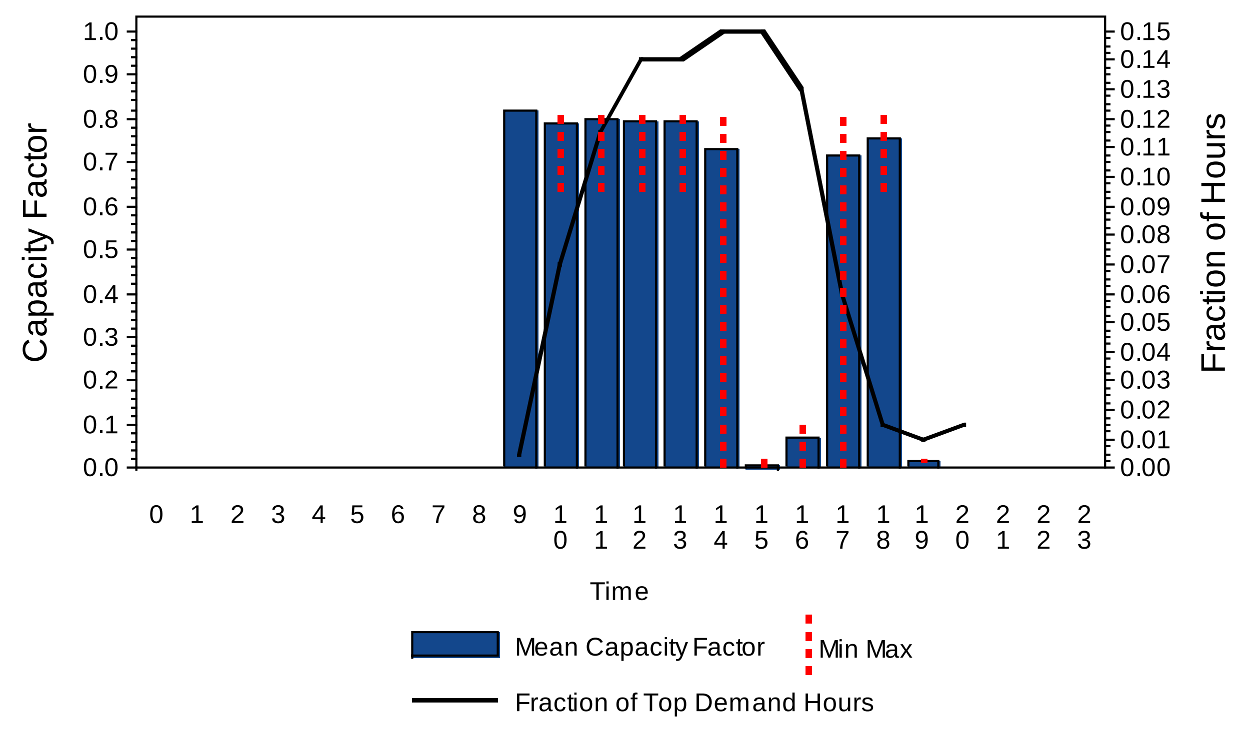


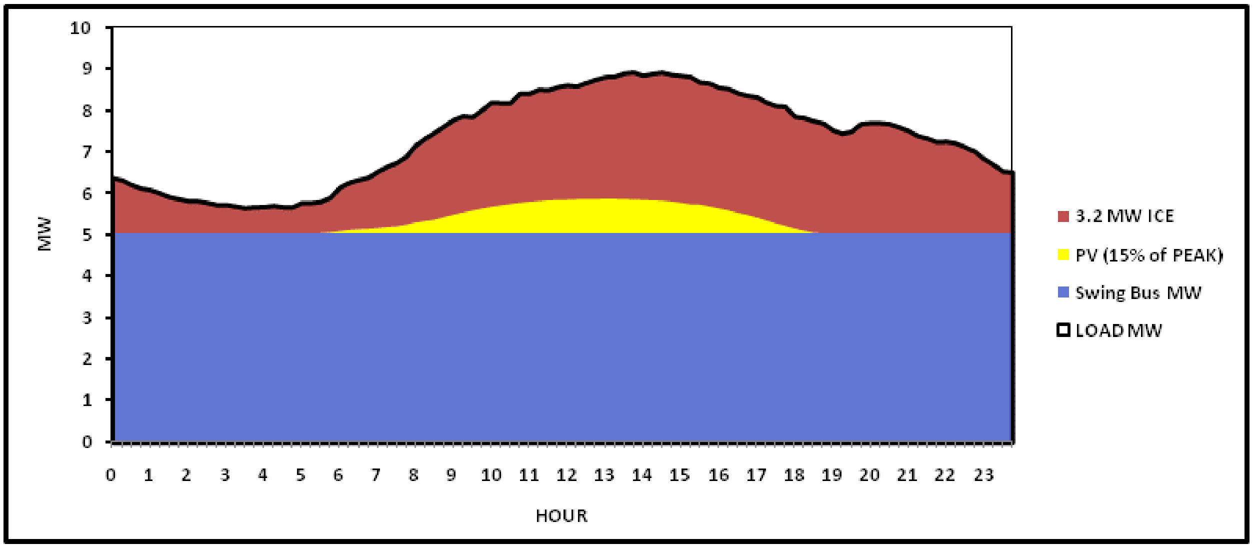
Figure A-3 shows the mean, maximum, and minimum capacity factors of the ICE operating on the C during the top 200 hours of feeder demand. The feeder consistently shows peak demand in the early afternoon and the ICE consistently underperforms for 3 to 5 P.M. This matches the peak day and is in fact present through out the year and in subsequent years. It is unclear why this ICE serving a retirement home regularly does not operate around 3 P.M.

**Figure A-3: DG Capacity Factor for Top 200 Hours of Demand on PG&E C**



The ICE unit is scaled to the maximum load following capacity of 3.2 MW, based on the load at the distributed generator location and the distribution line capacity. A 15% penetration of PV is added, as the PV peak occurs before the load peak as shown in Figure A-4.

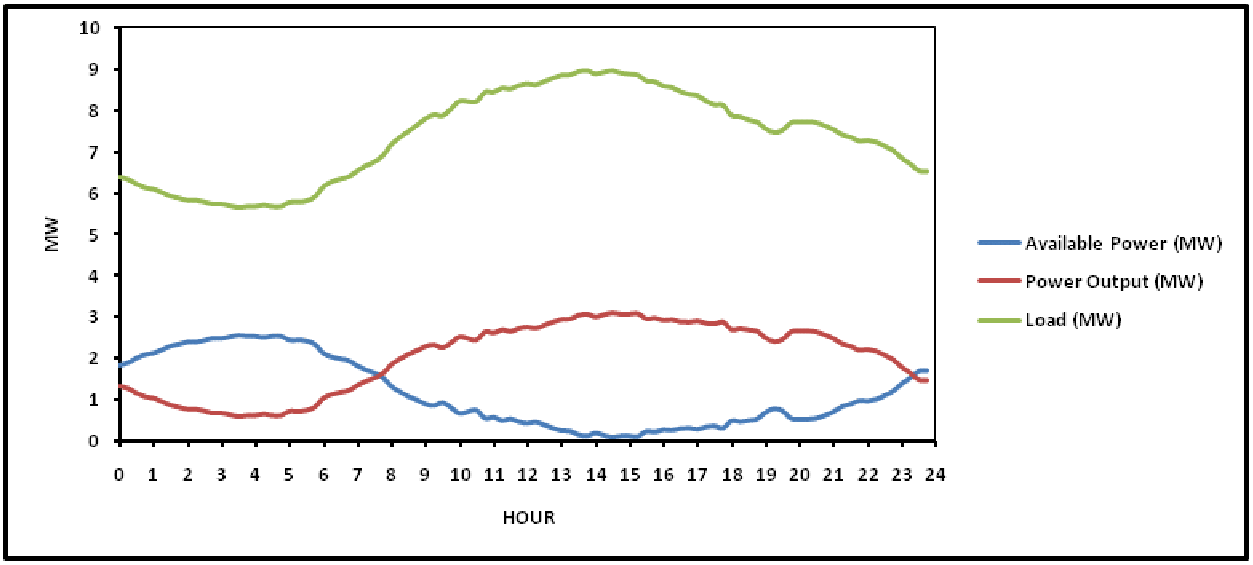
**Figure A-4: Plot of PG&E C, Combined with 15% (1.3 MW), PV, and a 3.2 MW ICE**




The PV peaks at approximately 1 P.M. in the PG&E C case. The feeder load peaks at approximately 3 P.M. Although these peaks are not matched perfectly the PV still provides benefit in reducing the load shortly before peak. The addition of a larger ICE allows the load following to continue past the feeder peak of 8.9 MW.

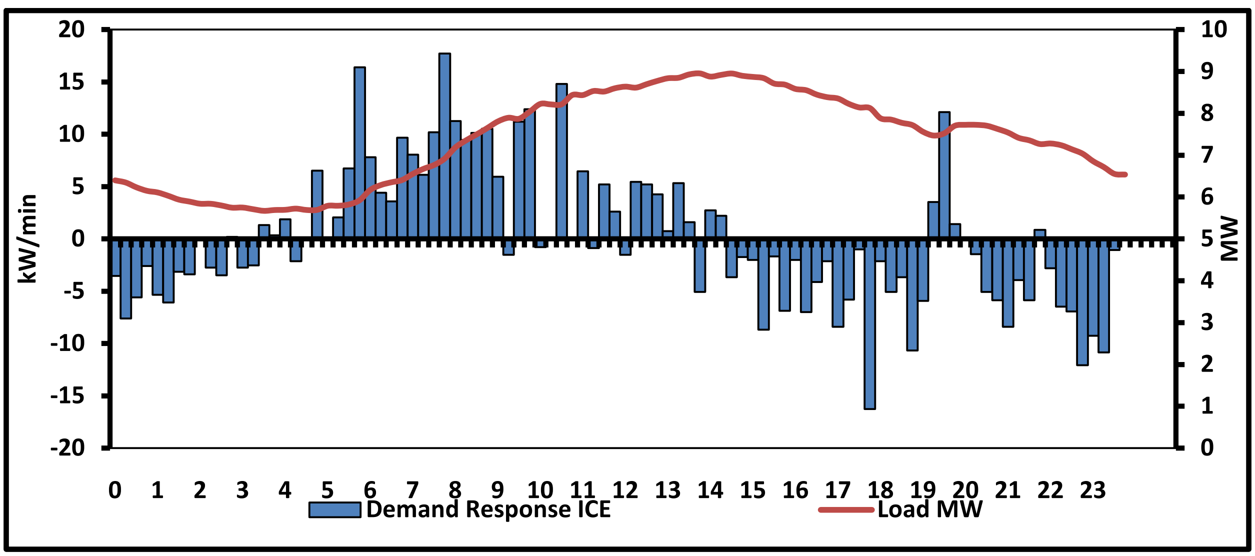
The available power, when operated alone or in combination with PV in PG&E C is plotted on Figure A-5.

**Figure A-5: Excess Power Available**

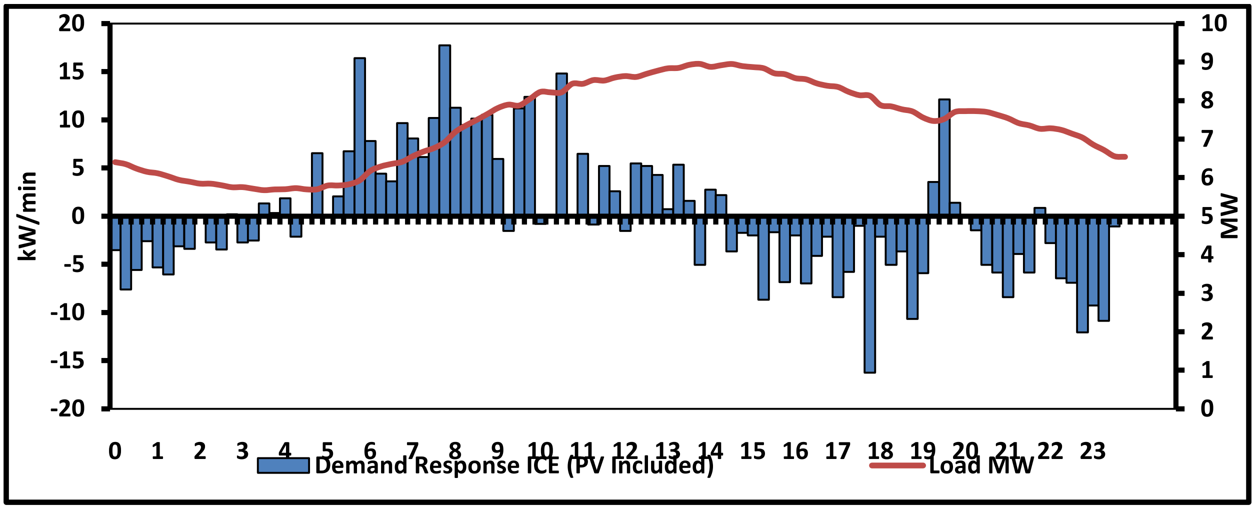



When the ICE is operated without PV, the minimum load is larger. The PV acts as a load reduction, therefore the minimum load required from the swing bus is less. More power is required from the ICE to serve the entire load. As more power is required from the ICE, less is available in an emergency or call for power situation. The ramp rate required is now plotted for each of these configurations.

**Figure A-6: Ramp Rate Required from ICE with PV**



### A-7: Ramp Rate Required from ICE without PV




The maximum ramp rate required from the ICE, calculated per 15-minute period is 17 kW/min up and down. The demand response requirements between the ICE and ICE with PV distributed generation are both very similar. The magnitude of demand response at the maximum ramp up and ramp down times, 7 to 8 A.M. and 5 to 6 P.M. are not assisted by the PV addition, but in the middle ours of the day a small amount less ramping is required of the unit due to the addition of PV.

### Table A-1: Energy from Different Generation Configurations over 24 Hours

| Configuration | Swing Bus MWh Over 24 Hours | ICE MWh Over 24 Hours | PV MWh Over 24 Hours |
|---|---|---|---|
| No DG | 176.7 MWh | N/A | N/A |
| Load Following ICE (4 MW) | 121.2 MWh | 50.7 MWh (60% of potential MWh) | N/A |
| Load Following ICE (3.2 MW)+ PV | 121.2 MWh | 48.9 MWh (60% of Potential MWh) | 6.6 MWh (50% of potential MWh over 10 hours, or 21% of potential MWh over 24 hours) |

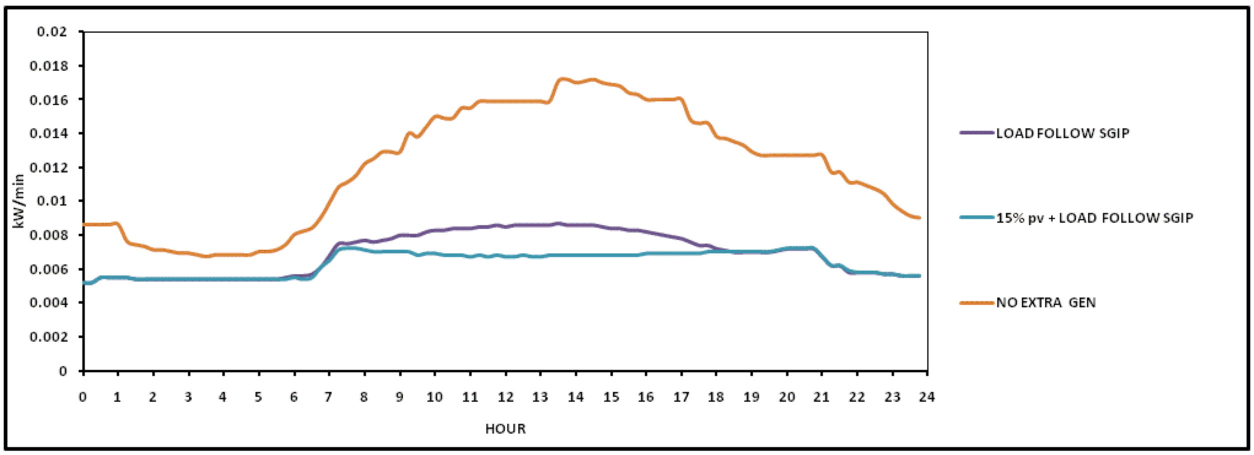
As the profile is very similar to PG&E B, the energy provided is also similar.

**Table A-2: Average Losses over 24 Hours of Peak Day**

| Scenario | Average MW Loss | % Change From NO DG |
|---|---|---|
| MW Losses NO DG | 0.01203 | 0% |
| MW Losses Original DG | 0.01194 | -1% |
| Losses Load Following 4 MW GEN | 0.00695 | -42% |
| Losses Load Following 3.2 MW DG + PV | 0.00635 | -47% |

Coupling a 3.2 MW ICE, with PV reduces the losses from the original level by an average of 47% over 24 hours. The 24-hour loss profile is reduced significantly from the original level by using the PV combined with the ICE. The ICE gives a significant reduction, but less of a reduction than when combined with PV in Figure A-8.

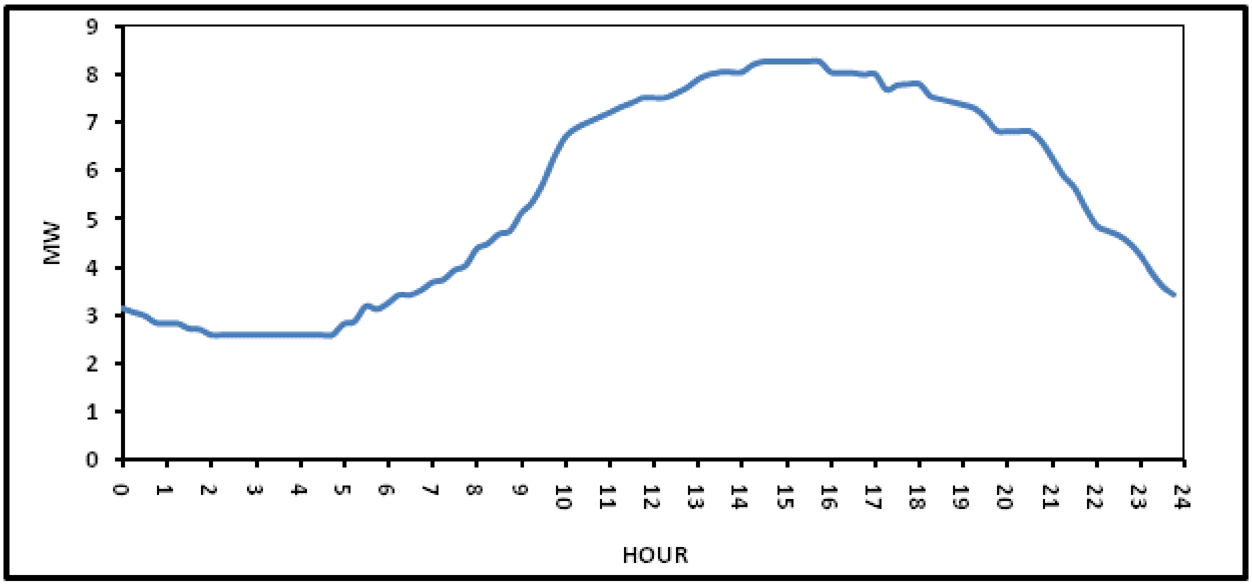
**Figure A-8: MW Losses over the 24-Hour Period with Different Generation Configurations**



### *PG&E A*

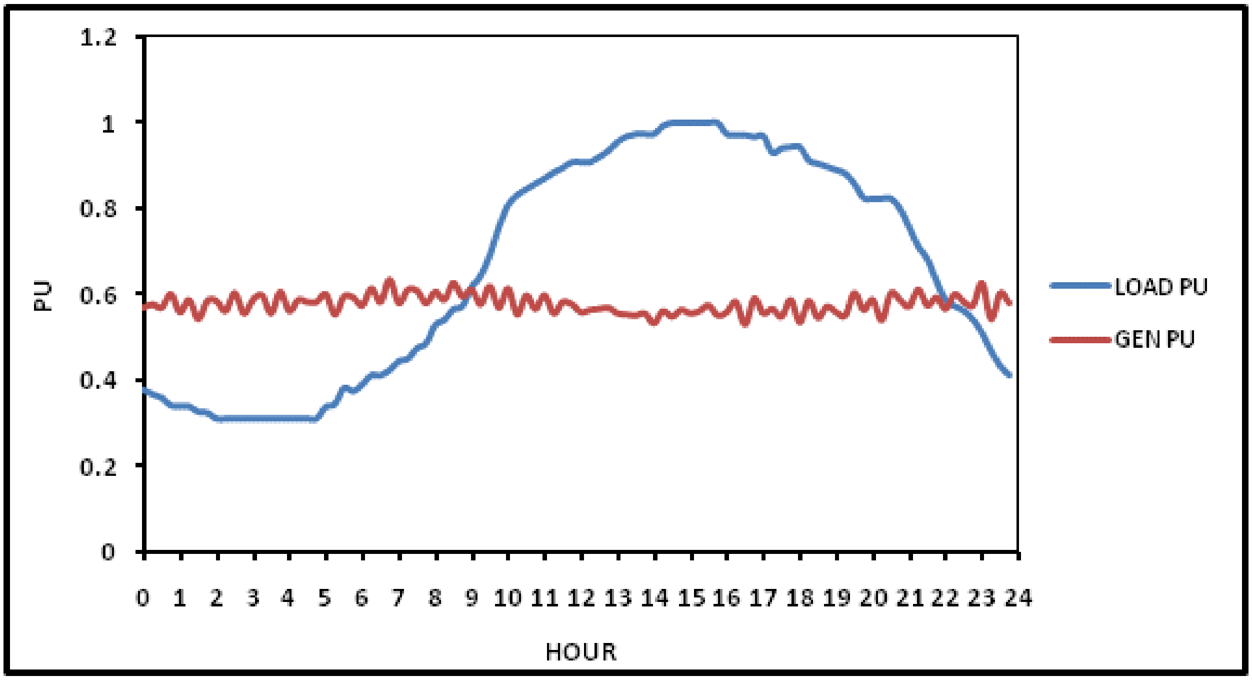
The A feeder in PG&E service area is located in Climate Zone 4. Figure A-9 shows the load profile. PG&E A peaks in the late afternoon (3 P.M.) and reaches a maximum load of approximately 8.2 MW. The distributed generator is a 300 kW ICE unit. There is little or no generation data for the actual peak day for PG&E A, but load data was available. The generation data is therefore replaced with a representative profile for the PG&E A generator at this time. A further description of these changes is presented in Section 3.

**Figure A-9: Load Profile for Peak Day (July 8, 2008)**



The output profile for the ICE generator is approximately a straight line at 60%. The generation and load are now plotted in a per unit form in Figure A-10.

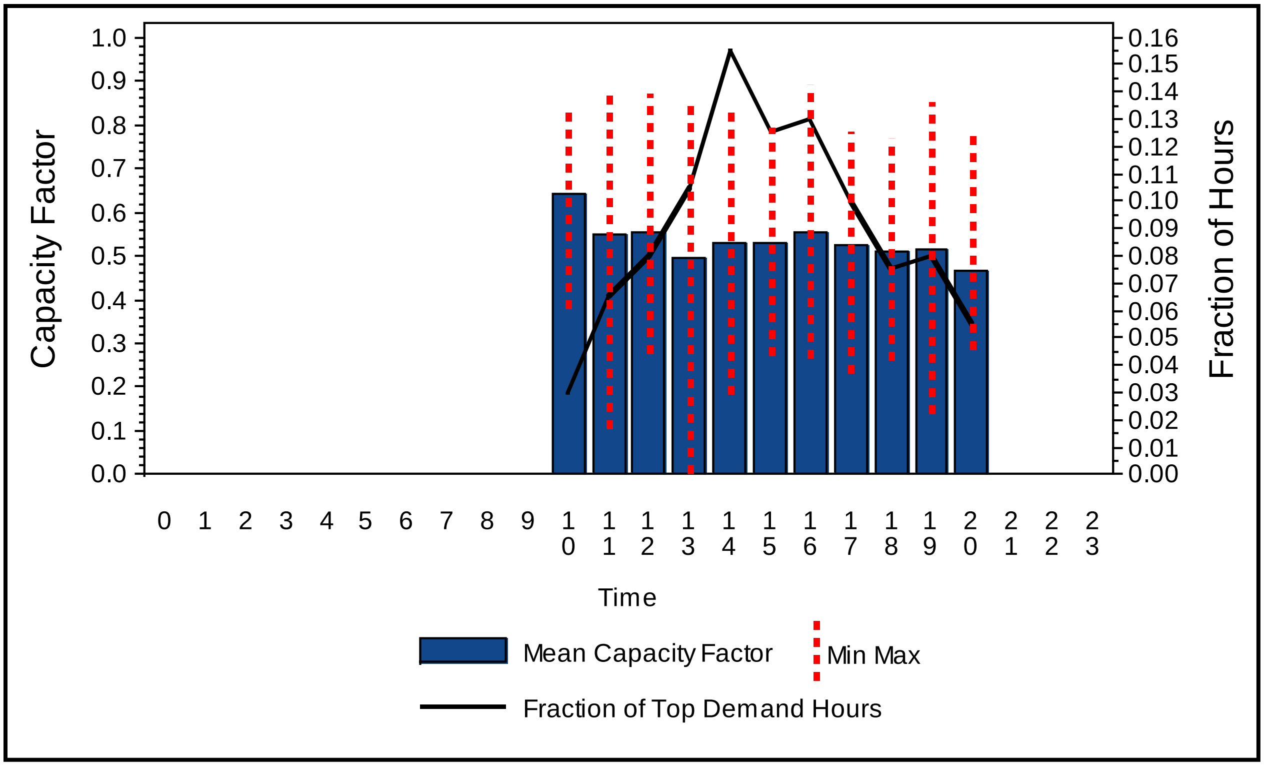
**Figure A-10: Per Unit Load Profile and MT Generation Profile***




* Original generator is 300 KW ICE Unit

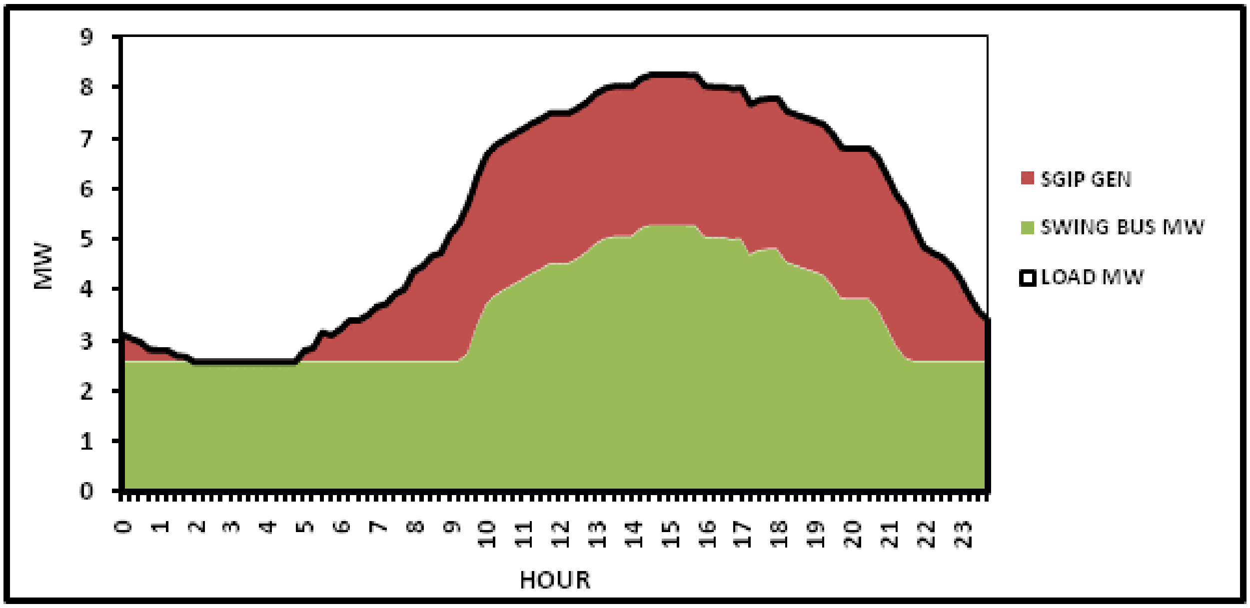
Figure A-11 shows the performance of the MT operating on the PG&E A feeder during the top 200 hours of feeder demand.

**Figure A-11: DG Capacity Factor During Top 200 Hours of Feeder Demand on PG&E A**



The distribution line near the DG location is rated at 3.7 MVA. In the other feeder analyses, the DG was increased up to the size of the distribution line rating. However, the minimum load is 3 MW for this feeder so the DG is limited to 3 MW max as shown in Figure A-12.

**Figure A-12: Additional 3 MW ICE Unit Added To PG&E A's Generation Profile**



The 3 MW ICE operates at a minimum capacity of zero (0) and a maximum of 3 MW. Between 10 A.M. and 9 P.M., the ICE unit is generating at maximum so the Swing Bus increases generation by 2.3 MW to meet load. There is a maximum deficit of 2.3 MW, which is provided by the swing bus. The ramping required for the 3 MW ICE unit, and the ramp rate required to meet the full load change are plotted in Figure A-13 and Figure A-14.

**Figure A-13: Rate Required For 3 MW ICE Only**

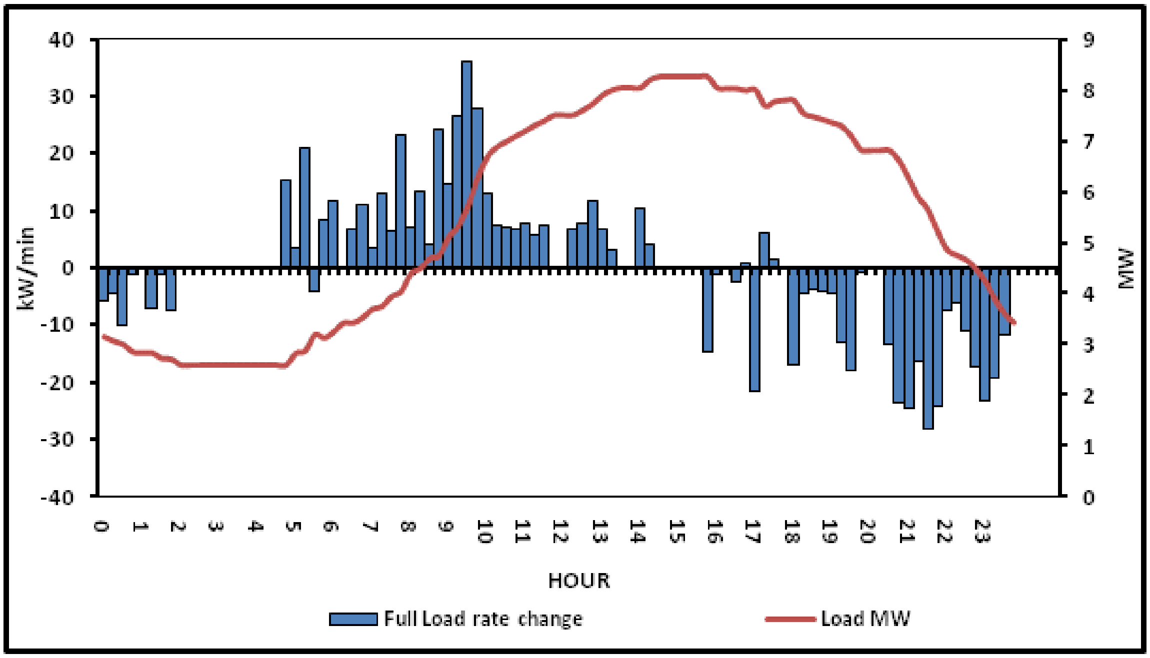
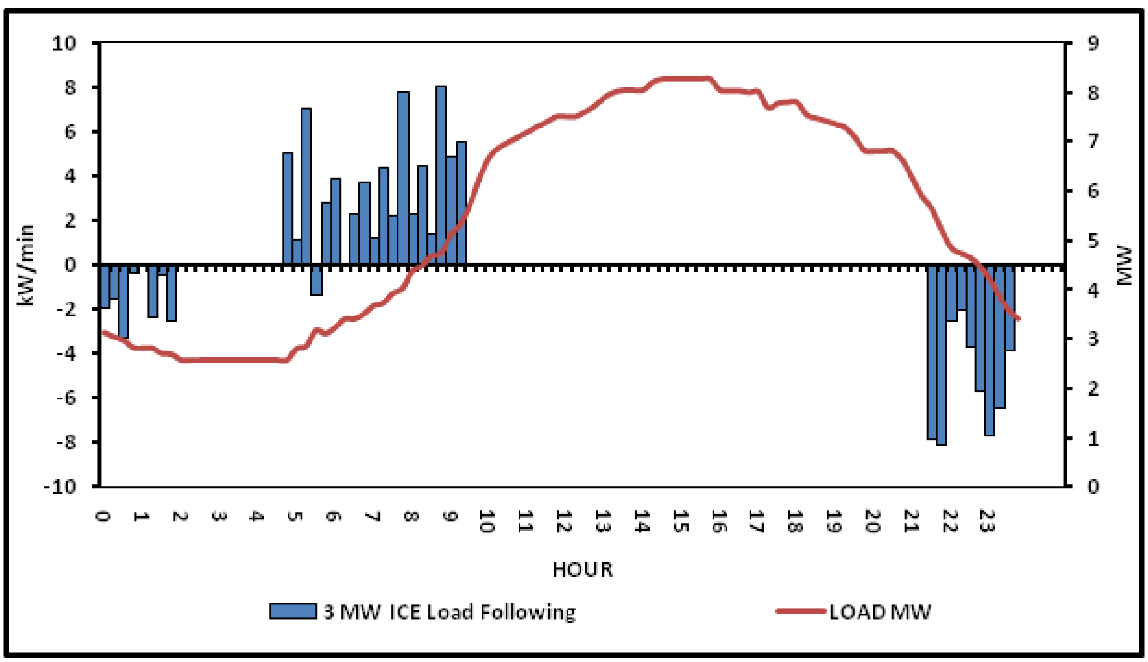
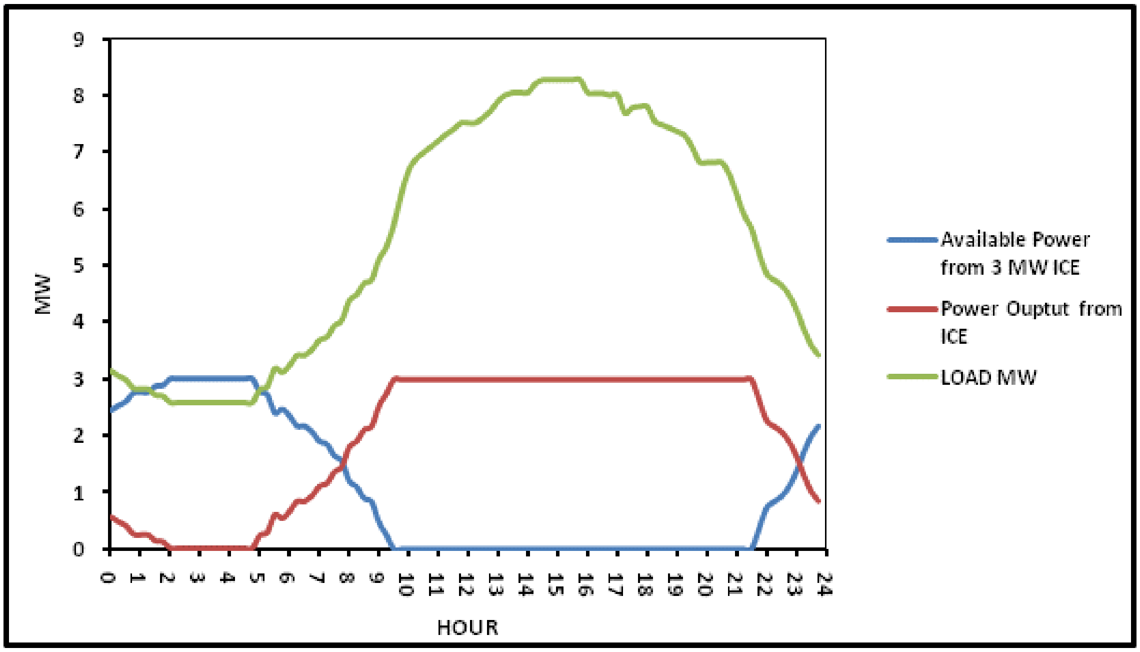



**Figure A-14: Rate Required For Full Load Change Rate**



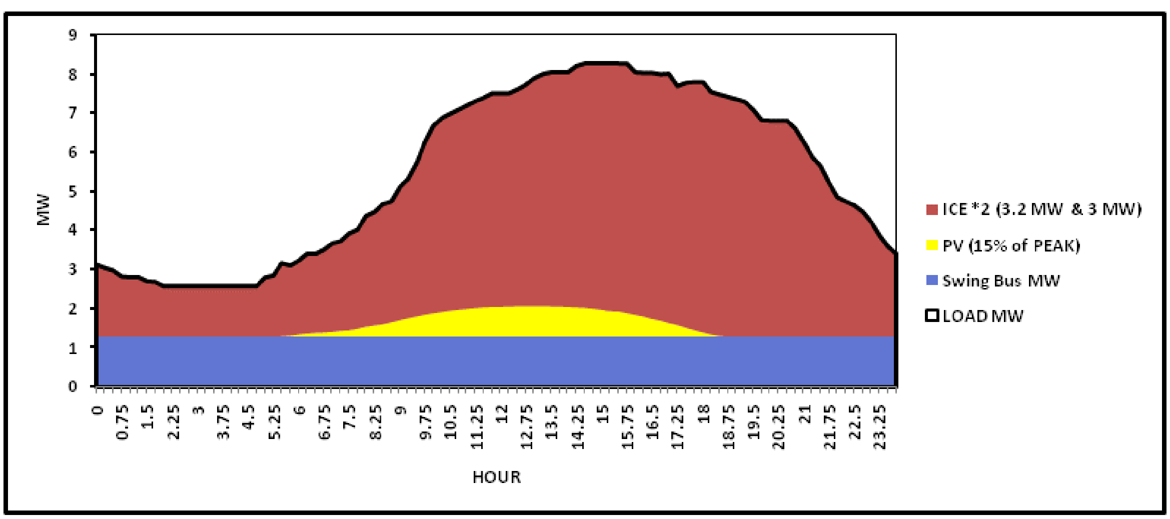
The available power from the scaled up ICE unit is limited during the maximum output hours as shown in Figure A-15. During the early morning minimum load period there is excess DG capacity, up to full capacity from 2 A.M. to 4 A.M.

**Figure A-15: Available Power From ICE Unit**




PV is added at dispersed locations along the feeder to approximately 15% of peak load, or 1.2 MW. Despite the addition of dispersed PV, there remains unserved load by the DG between 5 and 9 P.M. This is solved by the addition of a second generator in another location or increasing the generation from the Swing Bus.

**Figure A-16: PV Combined with Two ICE Units, 3 & 3.2 MW (15% of Peak Load for the PV, 1.2 MW)**



The ramp rates required for the ICE unit in this configuration and the available power is now compared (Figure A-17 and Figure A-18).

**Figure A-17: Required ICE Ramp Rates**

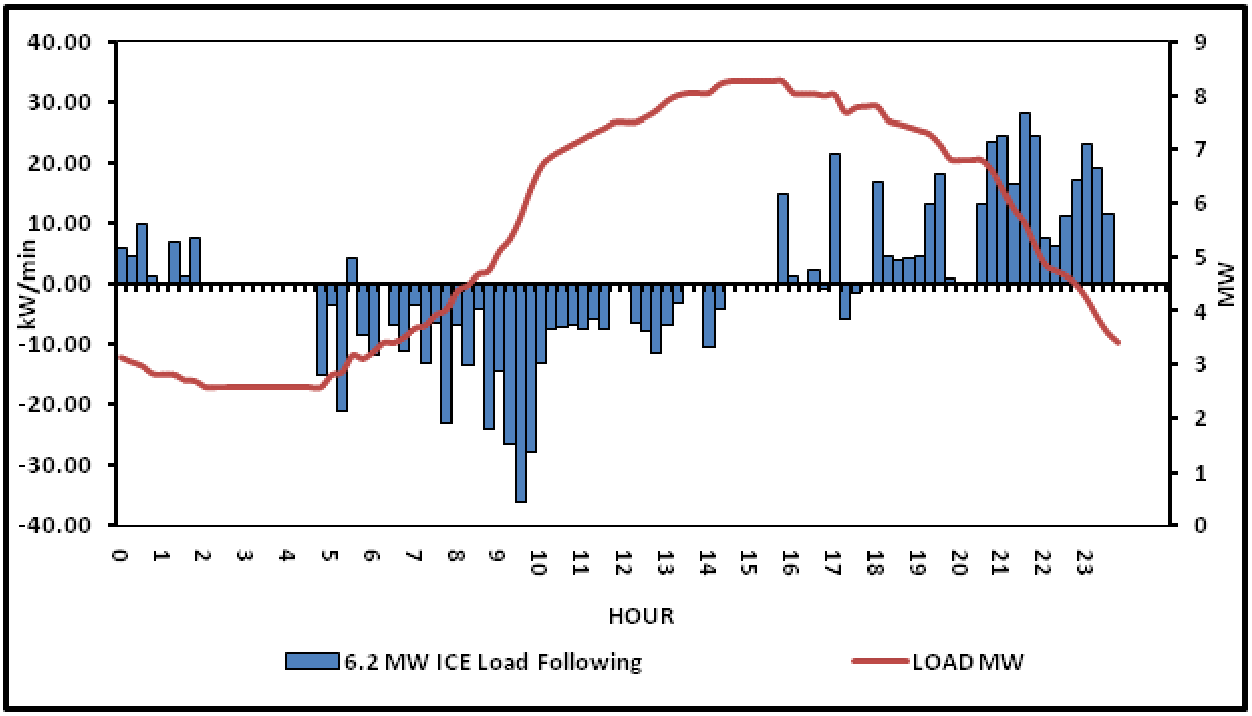
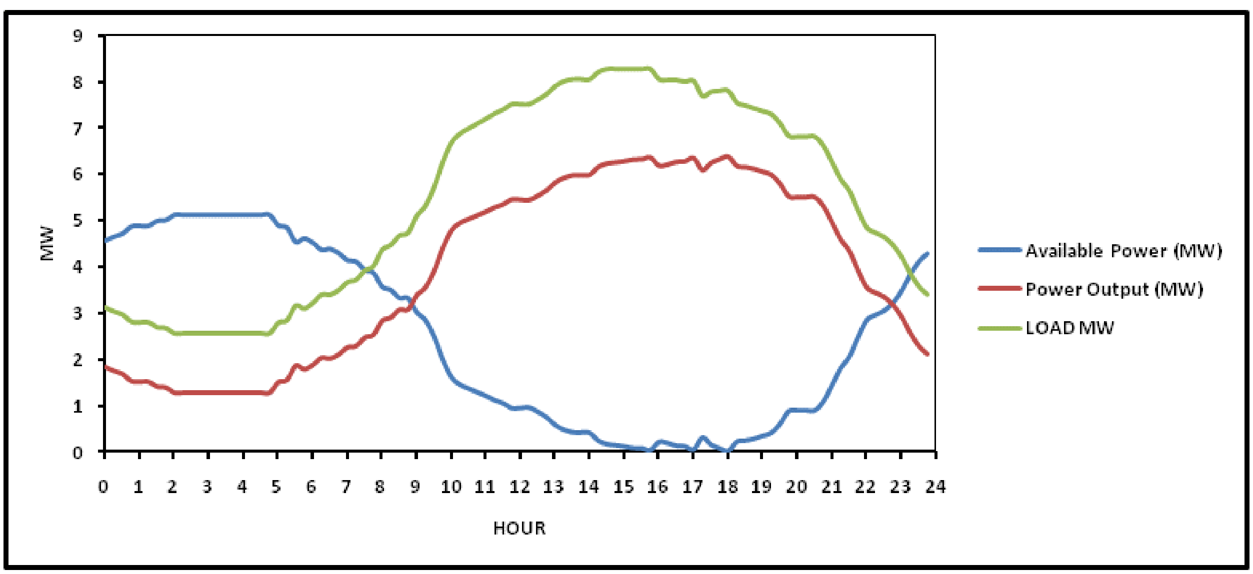



**Figure A-18: Available Power for PV & ICE**



The energy output for each generation is calculated in the same way as previous feeder configurations as shown in Table A-3.

**Table A-3: Energy Output in Different Generation Scenarios for PG&E A**

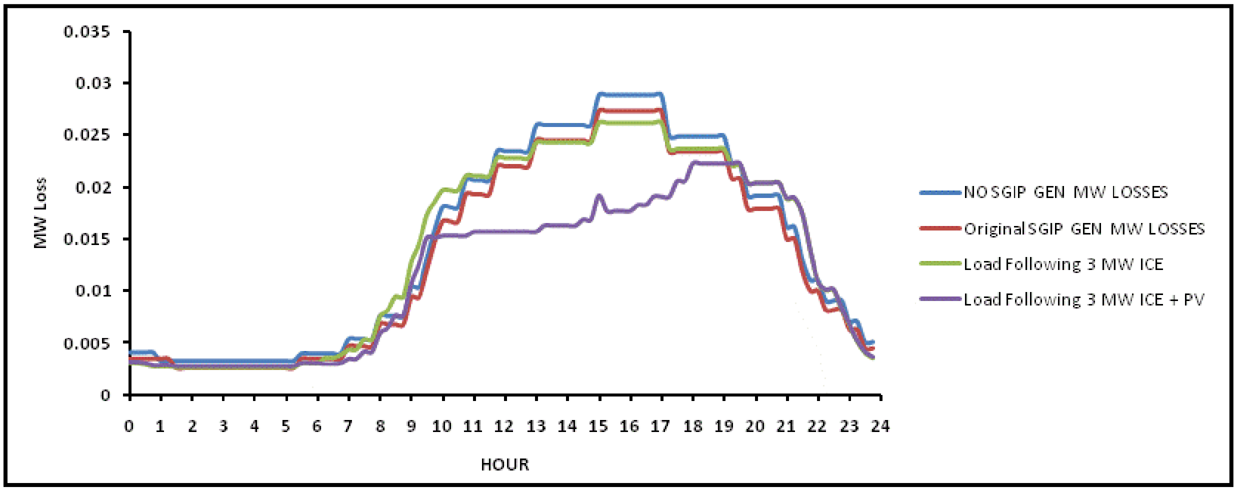
| Scenario | Swing Bus MWh Over 24 Hours | ICE MWh Over 24 Hours | PV MWh Over 24 Hours |
|---|---|---|---|
| No DG | 131.7 MWh | N/A | N/A |
| Load Following ICE (3 MW) | 90.6 MWh | 41.1 MWh (57% of Potential MWh) | N/A |
| Load Following ICE (6.2 MW)+ 15 % PV | 31.1 MWh | 94.6 MWh (63.5% of potential MWh) | 6.1 MWh (20% of potential if considered over 24 hours, 49% of potential is considered over 10 daylight hours) |

The average and 24 hour MW loss profile is simulated using Power World as in previous cases (Figure A-19, Table A-4).

**Table A-4: Average MW Loss for PG&E A over 24 Hours**

| Scenario | Average MW Loss | % Change From NO DG |
|---|---|---|
| MW Losses NO DG | 0.014 | 0% |
| MW Losses Original DG | 0.013 | -7% |
| Losses Load Following 3 MW GEN | 0.014 | -2% |
| Losses Load Following 6.2 MW DG + PV | 0.012 | -20% |

**Figure A-19: Losses Over 24-Hour Period With Different Generation Configurations**



Due to the high line loading in this feeder, the average losses show a much smaller decrease than in previous analyses. The biggest decrease is the combination of ICE and PV, which removes the peak loss hours and decreases the MW losses by approximately 20%.

## A.2 Summary of other SCE Feeders

### *SCE D*

The load data is an hourly format while the generation data is in 15-minute intervals. This caused the feeder demand curve to be a step function as compared to the generation profile. This does not impact the analysis. In Figure A-20, The D peak load of 6.36 MW occurs on June 13 at 7pm. The PV unit on the feeder is scaled to 1 MW and peaks at 1:30 P.M., which does not coincide with peak demand. The maximum difference between the maximum and minimum feeder demand is 4.46 MW of load.

**Figure A-20: SCE D Feeder Demand and 15% PV Profile**

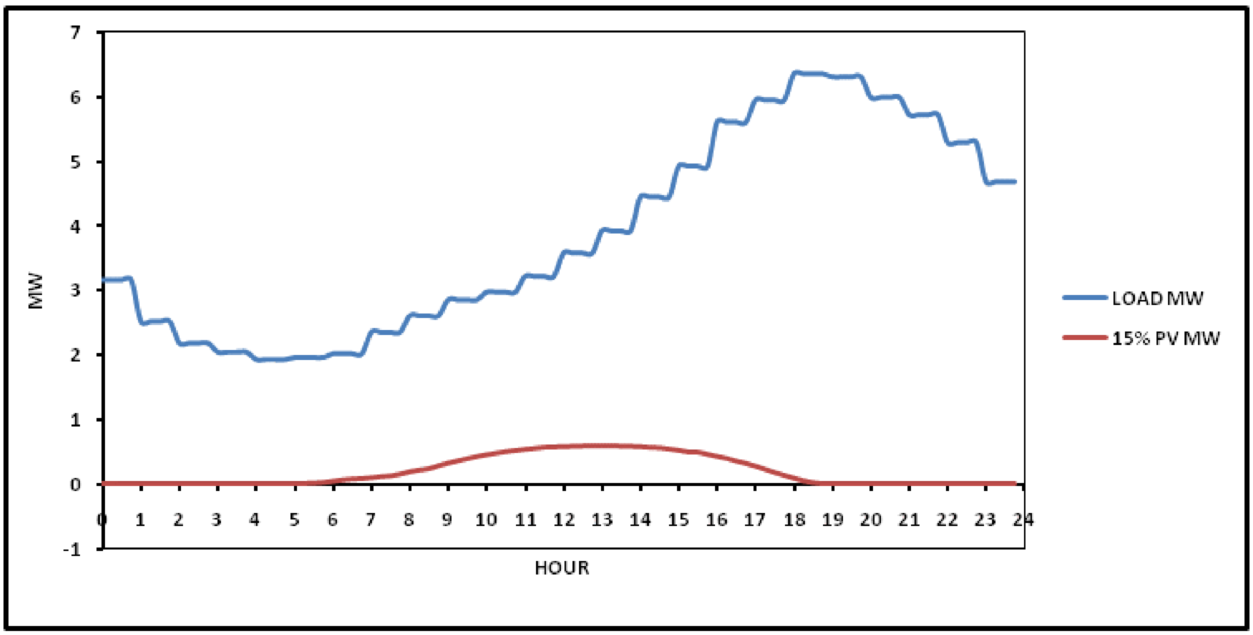
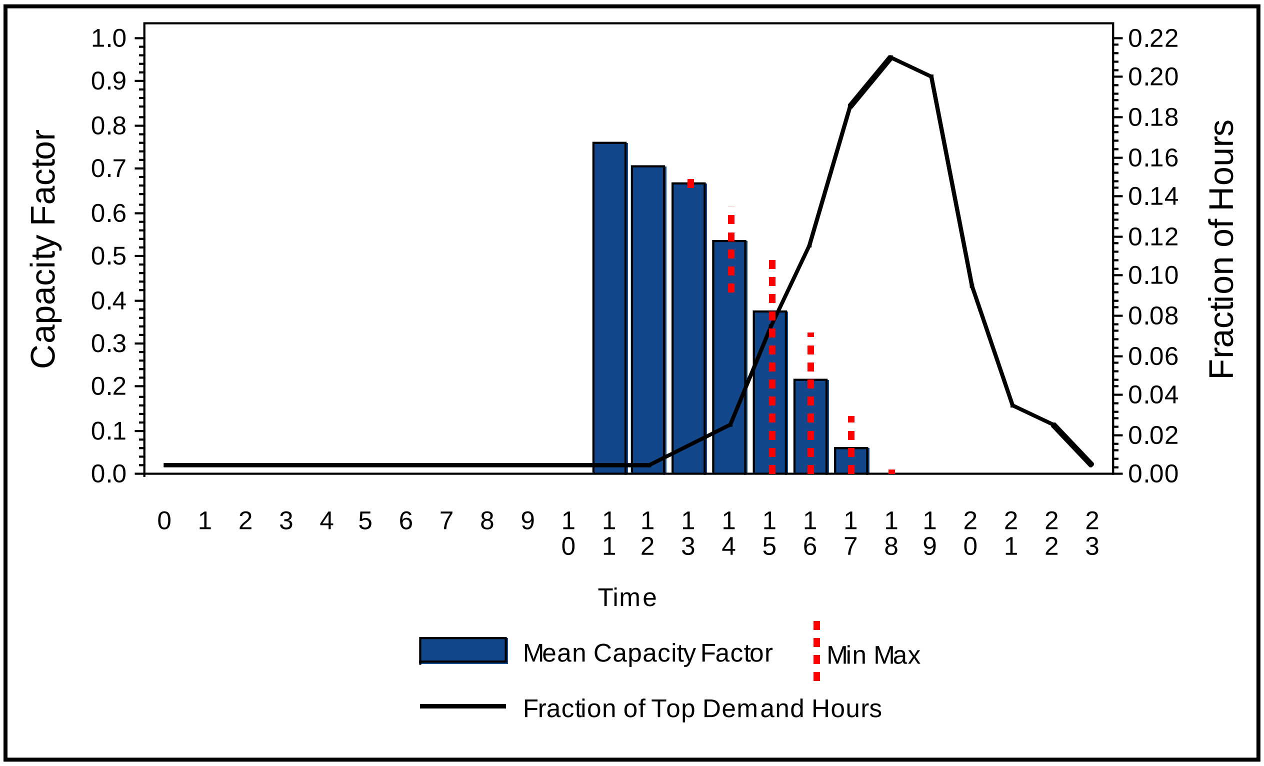


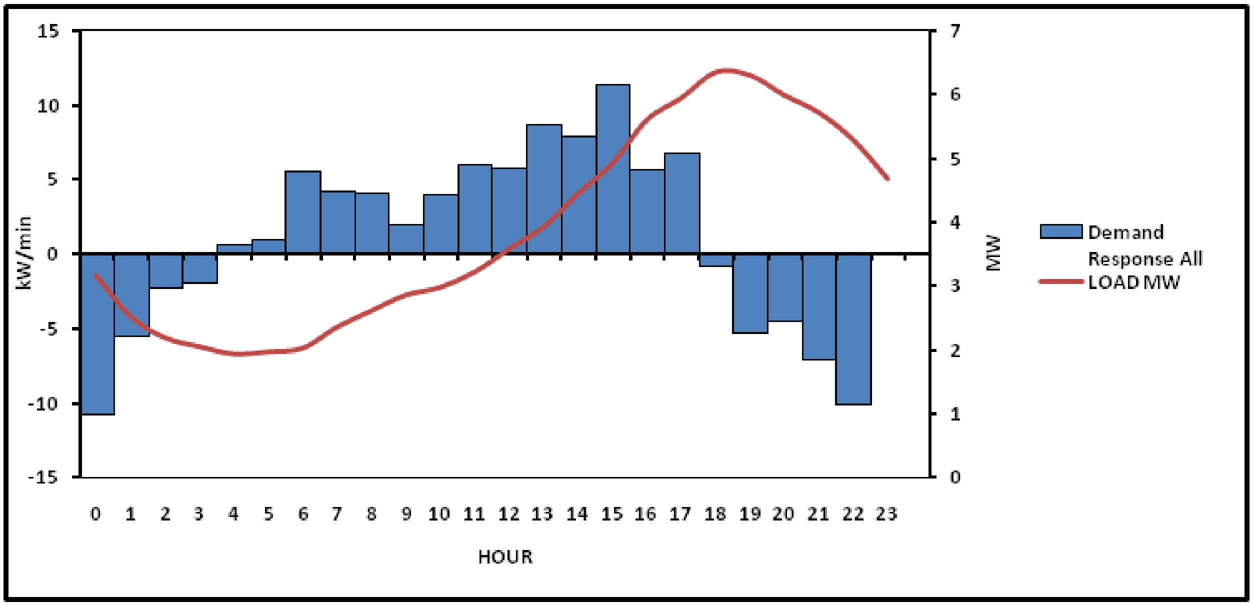
Figure A-21 shows the PV generation during the top 200 hours of feeder demand on the La Jolla feeder.

**Figure A-21: DG Capacity Factor During the Top 200 Hours of Feeder Demand**



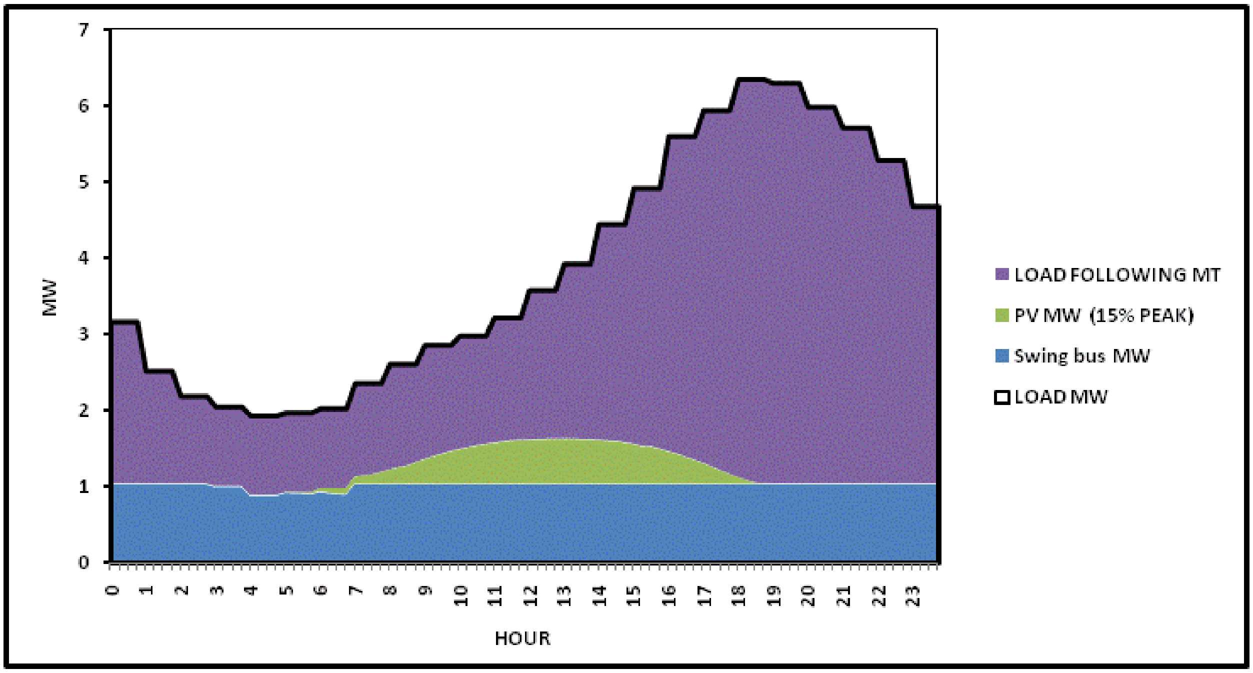
Below in Figure A-22, is the ramp rate required for additional MT or ICE units to adequately follow the SCE D feeder demand. The demand response requirement to adequately follow the feeder demand does not exceed 11 kW/minute. The peak response times occur during the midnight hours (11 P.M. to 1 A.M. and 3 P.M.). The demand response requirement is within the representative MT capabilities.

**Figure A-22: Required Ramp Rate for Load Following Units on SCE D**



The distributed generation on SCE D is shown in Figure A-23 to examine the benefits of adding a MT to meet the load on the feeder. This combination of DG resources is comprised of one 5.5 MW MT unit to serve the evening load when the feeder demand is at its highest. The Swing Bus remains at a 1 MW level though out this entire analysis, apart from a small dip between 4 and 7am. This is due to the required minimum level of generation and the required magnitude of generation conflicting with the minimum swing bus demand.

**Figure A-23: New DG Profiles with Load Following Capability for SCE D**



In Figure A-24, the demand response of the MT unit is graphed below. The maximum kW/min requirement is 12 kW/min. The demand response of the MT unit responds to the feeder demand because the MT is set up as a load following unit. Very similar to Figure A-22, the peak demand response times for the MT occur during the midnight hours (11 P.M. to 1AM) and late afternoon hour (3 P.M.).

**Figure A-24: Ramp Rate Required for New DG units on SCE D**

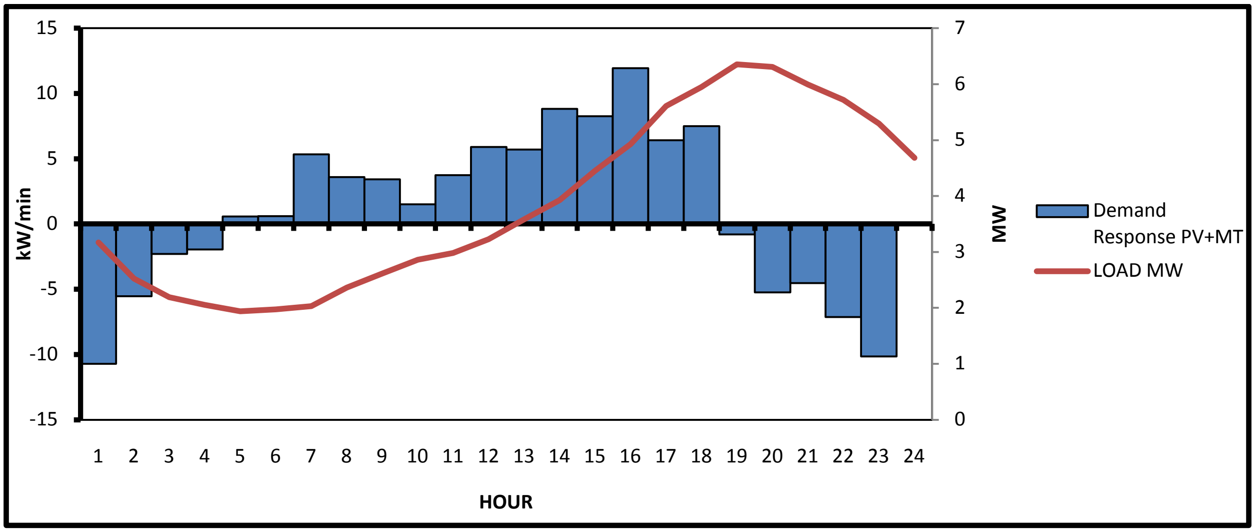



Table A-5 displays the energy provided by several generation configurations. Under the "no distributed generators", the Swing Bus provides 92.7 MWh over a 24-hour period. The Swing Bus energy can be as low as 24.5 MWh under certain scenarios.

**Table A-5: Energy Provided by Generators and Swing Bus For SCE D**

| Scenario | Swing Bus MWh over 24 Hours | PV MWh over 24 Hours | MT MWh over 24 Hours |
|---|---|---|---|
| No DG | 92.7 MWh | N/A | N/A |
| 1 MW PV Generator | 88.1 MWh | 4.7 MWh (19% of potential over 24 hours, 47% of potential over 10 daytime hours) | N/A |
| 1 MW PV and 5.5 MW MT | 24.5 MWh | 4.7 MWh (19% of potential over 24 hours, 47% of potential over 10 daytime hours) | 63.6 MWh (53% of potential over 24 hours) |

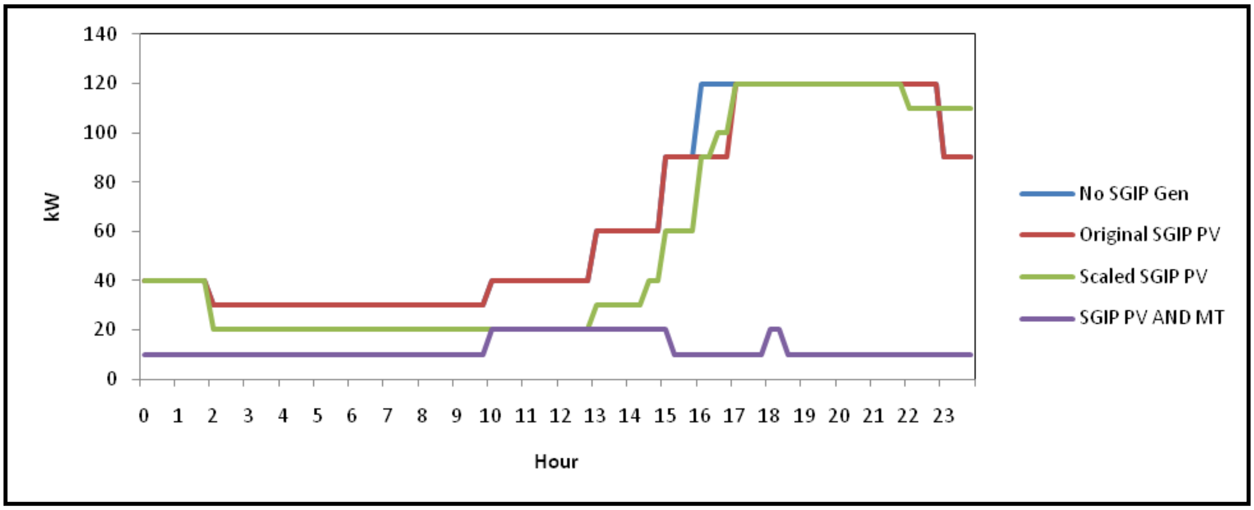
Table A-6 below shows the average MW losses under different configurations. The average MW loss with no DG is 0.0658 MW, or 65.8 kW. With all DG units in service, the average feeder losses reduce by over 80%, averaging 0.0124 MW or 12.4 kW.

**Table A-6: Average Losses over 24 Hour Simulation for SCE D**

| Scenario | Average MW Loss | % Change |
|---|---|---|
| No DG | 0.0658 | 0.0% |
| 1 MW PV Generator | 0.0619 | 5.9% |
| 1 MW PV and 5.5 MW MT | 0.0124 | 81.1% |

Figure A-25 displays the feeder losses over the 24-hour simulation period. The blue line is the kW losses with no distributed generation. The purple line is the kW loss with all the DG included. Diversifying the DG mix clearly reduces the losses on the feeder.

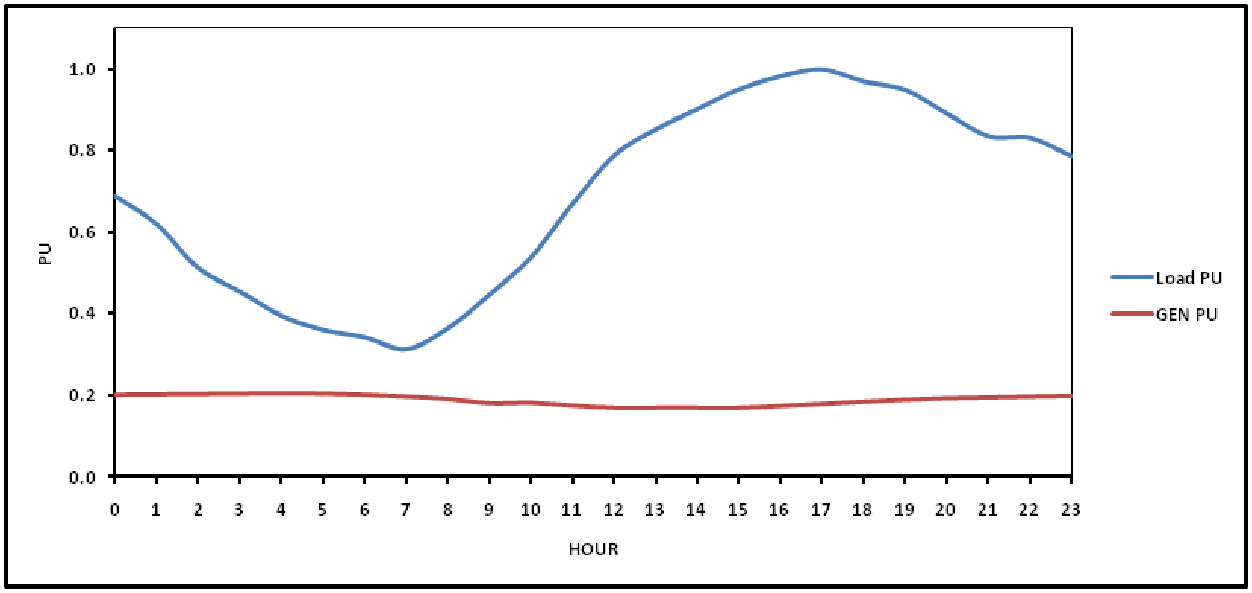
**Figure A-25: Average Feeder Losses for SCE D**



### *SCE B*

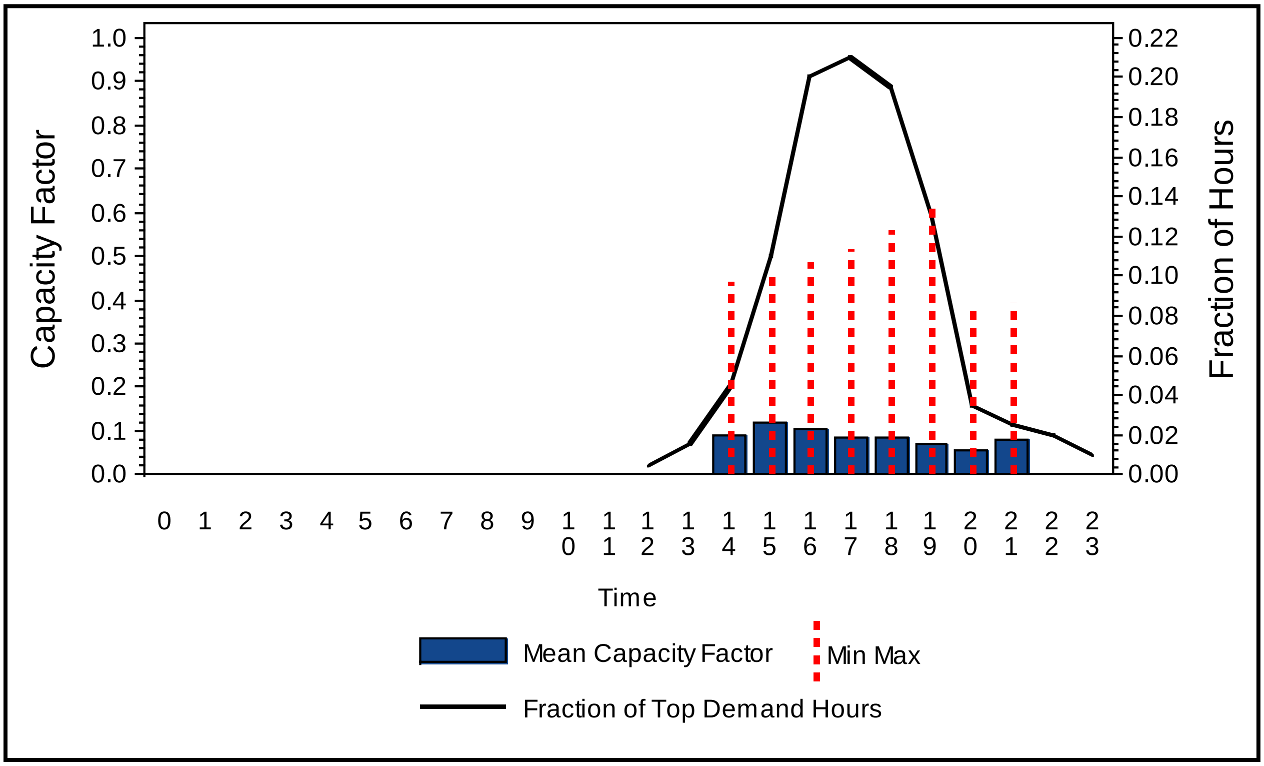
Figure A-26 displays the SCE B feeder demand profile along with a representative day for the 60 kW SCE B MT. The SCE B peak load of 6.4 MW occurs on September 7 at 4 P.M. The original MT is rated at 60 kW but is scaled in the following analysis to determine the benefit of the DG at larger penetration levels. Since SCE B belongs in an inland type climate range, the MT profile is base loaded. SCE B's generation data is missing for the peak day, so as in previous cases (PGE A and SCE C) the data is replaced with a representative profile for this generator from another time.

**Figure A-26: SCE B Feeder Demand and 60 kW MT Profile**



The low peak day capacity factor is confirmed when looking at performance during the top 200 hours in 2008. This is shown in Figure A-27. Performance during 2007 was significantly better while performance in 2009 was virtually zero, indicating the potential that the MT was beginning to experience reliability problems in 2008 that became more pronounced in 2009.

**Figure A-27: DG Capacity Factor During top 200 Hours of Feeder Demand**



In Figure A-28, the micro-turbine is graphed along the Swing Bus that is fixed at just under 1 MW. The area remaining in red is the required capacity from additional units to meet the feeder demand. The maximum difference between the maximum load and minimum load is 4.5 MW.

**Figure A-28: SCE B DG MT Profile and Load Following Requirement**

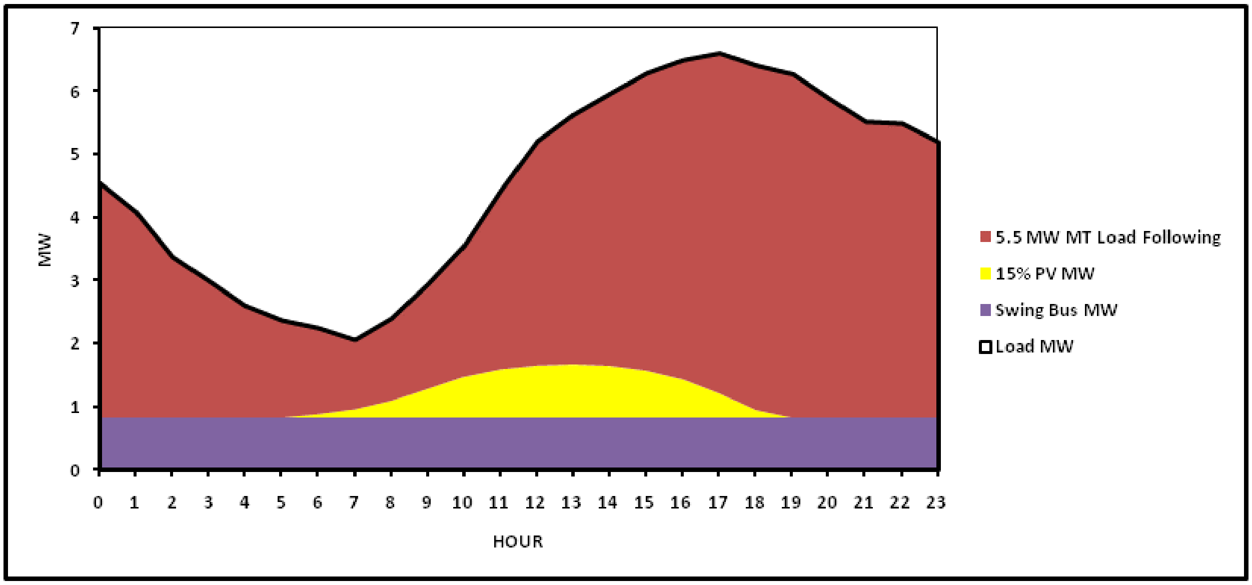


Figure A-29 and Figure A-30 show the demand response required to meet the feeder demand, as well as the demand response necessary of the MT unit on the feeder. The demand response for all in has a limit of 13 kW/min, whereas in Figure A-30, the demand response for MT/ICE unit has a limit of 15 kW/min. This is a difference of 2 kW/min. The peak demand response times between both graphs occur at the same times of the day, however, at different response rates.

**Figure A-29: Required Ramp Rate for Load Following Units on SCE B**

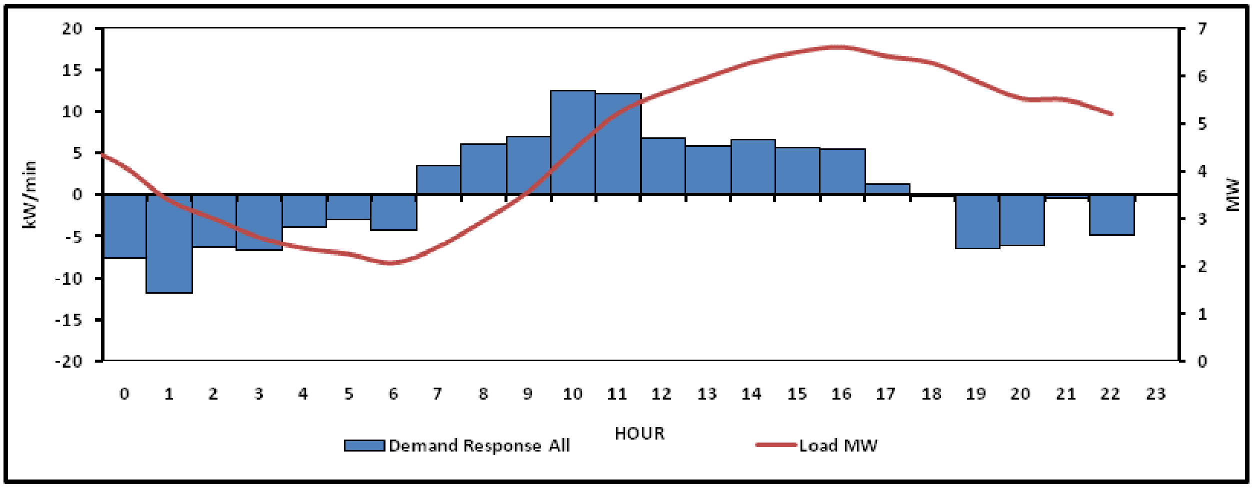
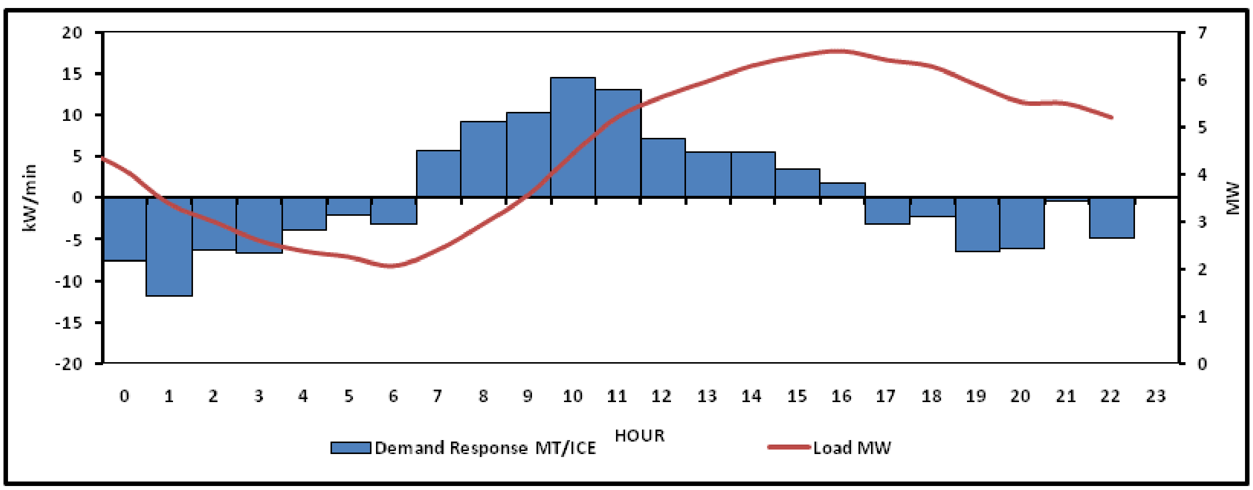



**Figure A-30: Required Ramp Rate for New DG Units on SCE B**



In Table A-7, the daily energy calculations are broken down by technologies and groups. If SCE B were provided with utility energy, the feeder would consume 108.6 MWh. However, with one 5.8 MW MT SGIP generator providing 87 MWh throughout the 24 hr period, the energy the swing bus will have to provide is 21.6 MWh. When the DG penetration was additional PV, the utility would provide 19.9 MWh, where as the MT provides 82.1 MWh and the PV unit contributing 6.7 MWh.

**Table A-7: Energy Provided by Generators and Swing Bus for SCE B**

| Scenario | Swing Bus MWh over 24 Hours | MT MWh over 24 Hours | MT, PV, and ICE MWh over 24 Hours |
|---|---|---|---|
| No DG | 108.6 MWh | N/A | N/A |
| 5.8 MW Load Following DG | 21.6 MWh | 87.0 MWh (62% of Potential MWh) | N/A |
| 5.5 MW + 15% PV MWh | 19.9 MWh | 82.1 MWh (62.2% of Potential MWh) | 6.7 MWh (31% of potential MWh over 24 hours, 74% of potential MWh over 10 daytime hours) |

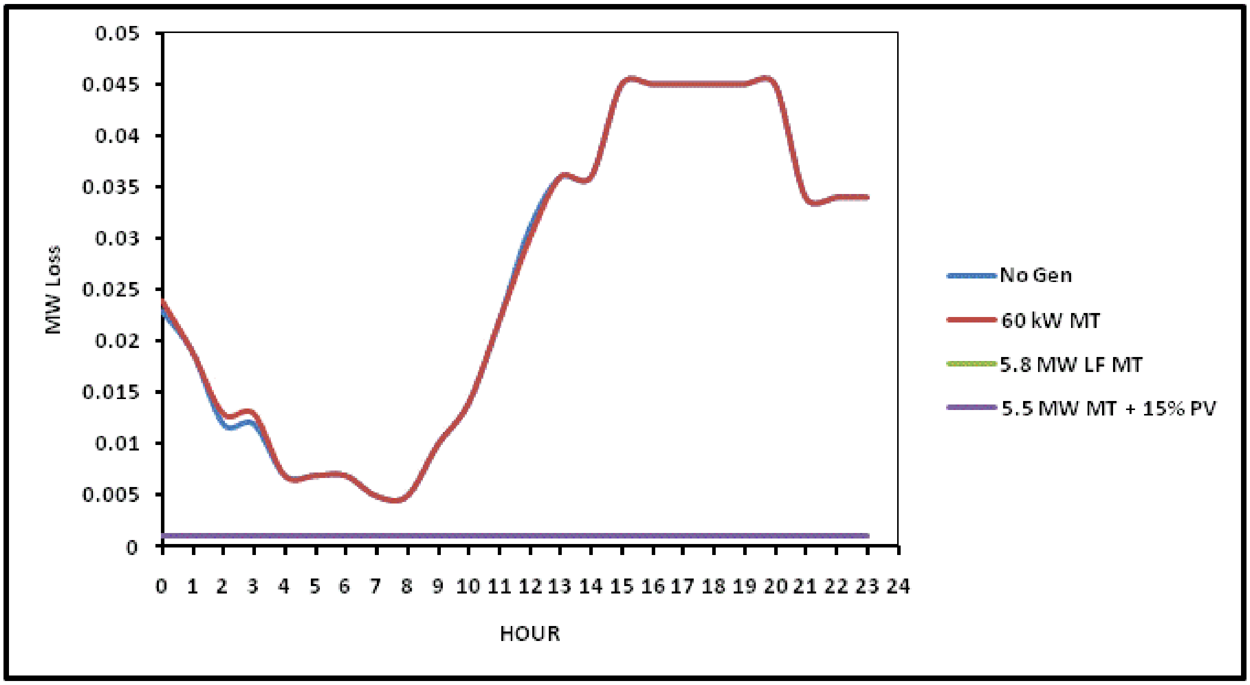
The feeder losses are tracked to determine the effectiveness of additional distributed generators. Table A-8 below shows the average MW loss for the entire feeder under the different SGIP configurations. The average loss with no DG is 0.026 MW or 26 kW. When all of the DG units are online, this reduced the average MW losses by over 95%, averaging 1 kW of losses on the feeder.

**Table A-8: Average Losses over 24 hour Simulation for SCE B**

| Scenario | Average MW Loss | % Change |
|---|---|---|
| NO DG | 0.026 | 0.00% |
| Original DG | 0.026 | 0.32% |
| 5.8 MW Load Following DG | 0.001 | -96.1% |
| 5.5 MW + 15% PV MWh | 0.001 | -96.1% |

In Figure A-31, graphs the feeder losses over the 24-hour simulation period. Four simulations are graphed and the benefit that DG is providing as their penetrations are increased. With no DG graphed in blue, it is designated as the reference. Slowly, as the DG penetration is increase, the losses on the feeder become less as shown by the green and purple line with PV and MT units on the feeder.

**Figure A-31: Average Feeder Losses for SCE B**




## A.3 Summary of Other SDG&E Feeders

Due to power flow modeling issues, the remaining feeder SDG&E C in SDG&E's area are not used for analysis.

# Appendix B

## Methodology and Results for Establishing Representative Generation Profiles and Site Demand Profiles

### B.1 Introduction

This appendix includes descriptions of and results for three separate analyses that were conducted as part of an effort to 1) develop generation load profiles for distributed generation (DG) technologies, 2) develop demand profiles based on site-level data, and 3) explore the relationship between generation and demand both at the site level and overall. In addition to providing a better understanding of DG technologies, the load profiles also serve as inputs into other analyses, primarily the cost-effectiveness engine used to evaluate the economic benefits associated with participation in the SGIP.

The data sources used in the analysis for this appendix include:

- Program tracking data: Information on the site (location, type of facility) and technology characteristics (type and capacity of the unit).
- Generation data: 15-minute kWh readings showing the generation output from the DG units for participant sites in SCE, SDG&E, and PG&E service territories.
- Site demand data: For PG&E only, 15-minute kW readings for a subset of sites with generation data.

The analysis examined data from summer (June through September) of 2008 and included only sites with fuel cells, gas turbines, internal combustion (IC) engines, or microturbines. In addition to stratifying by technology, the analysis also differentiated sites based on the location (coastal versus inland) and a general site type to distinguish between usage patterns based on occupancy (e.g., hotels) and process (e.g., industrial sites) facilities. The site type category was developed from the two-digit NAICS code, for which the mapping is presented in Table B-1. For a few cases with either missing or ambiguous NAICS information, the sites were manually classified based on the site name.

**Table B-1: NAICS Code Mapped to Occupancy and Process Site Types**

| Two-Digit NAICS Code | NAICS Title | Site Type |
|---|---|---|
| 11 | Agriculture, Forestry, Fishing and Hunting | Process |
| 21 | Mining | Process |
| 22 | Utilities | Process |
| 23 | Construction | Process |
| 42 | Wholesale Trade | Occupancy |
| 51 | Information | Occupancy |
| 52 | Finance and Insurance | Occupancy |
| 53 | Real Estate and Rental and Leasing | Occupancy |
| 54 | Professional, Scientific, and Technical Services | Occupancy |
| 55 | Management of Companies and Enterprises | Occupancy |
| 56 | Administrative and Support and Waste Management and Remediation Services | Occupancy |
| 61 | Educational Services | Occupancy |
| 62 | Health Care and Social Assistance | Occupancy |
| 71 | Arts, Entertainment, and Recreation | Occupancy |
| 72 | Accommodation and Food Services | Occupancy |
| 81 | Other Services (except Public Administration) | Occupancy |
| 92 | Public Administration | Occupancy |

Table B-2 provides the initial number of sites with generation data by technology type, location, and site type. These figures are before any attrition due to missing or unreliable data.

**Table B-2: Initial Count of Sites with Generation Data**

| | | Site Type | | |
|---|---|---|---|---|
| | | Occupancy | Process | Total |
| Technology | Location | Sites | Sites | Sites |
| Fuel Cell | Coastal | 7 | 1 | 8 |
| | Inland | 3 | 4 | 7 |
| | Total | 10 | 5 | 15 |
| Gas Turbines | Coastal | 0 | 3 | 3 |
| | Inland | 1 | 1 | 2 |
| | Total | 1 | 4 | 5 |
| IC Engine | Coastal | 42 | 17 | 59 |
| | Inland | 30 | 20 | 50 |
| | Total | 72 | 37 | 109 |
| Microturbine | Coastal | 27 | 11 | 38 |
| | Inland | 19 | 9 | 28 |
| | Total | 46 | 20 | 66 |
| **All** | **Total** | **129** | **66** | **195** |

## B.2 Development of Generation Profiles

The objective of this first set of analyses was to use each site's metered DG output data to identify patterns that could be used to classify its generation profile as either "baseload" or "non-baseload." A baseload generation profile implies a relatively consistent level of output, whereas non-baseload is indicative of much more volatility. The general idea underlying the approach is that non-baseload sites will have more variation in their usage patterns as the output of a unit is ramped up and down to follow a site's demand. This volatility can be measured in the generation data and used to differentiate sites.

The two steps in this analysis were to develop a metric for volatility and then determine the thresholds associated with non-baseload profiles versus baseload profiles. A number of different ideas for measuring volatility were explored, including the calculation of different ratios of minimum, maximum, and mean generation values over a different time periods. Many of these worked well for some cases but were not consistent enough in their classifications to apply as a general measure of volatility. For this analysis, the most stable metric for load volatility tested for this analysis was the percent deviation of each generation observation from the mean of non-zero generation values for the day. The exclusion of zero generation values was necessary because units frequently shut down for extended periods during the day, dramatically lowering the mean output and showing variability that was rarely due to an attempt to ramp up to site demand. The comparison to the daily mean generation as opposed to the overall mean generation was necessary because many sites have unit output that is clearly level on individual days, but each day is also representative of substantially different capacity factors.

To demonstrate what this metric looks like, Figure B-1 and Figure B-2 present examples of volatile and non-volatile loads, respectively, for a single day. As Figure B-1 shows, the generation goes up and down frequently throughout the day, with individual observations ranging from 40% to 160% of the mean. In contrast, Figure B-2 shows generation output that operates at fairly steady levels. With the exception of one mid-morning drop to 40% of the mean, the levels of output do not deviate much at any other time of the day.

**Figure B-1: Example of a Volatile Load Day—Generation as Percent of Daily Mean**

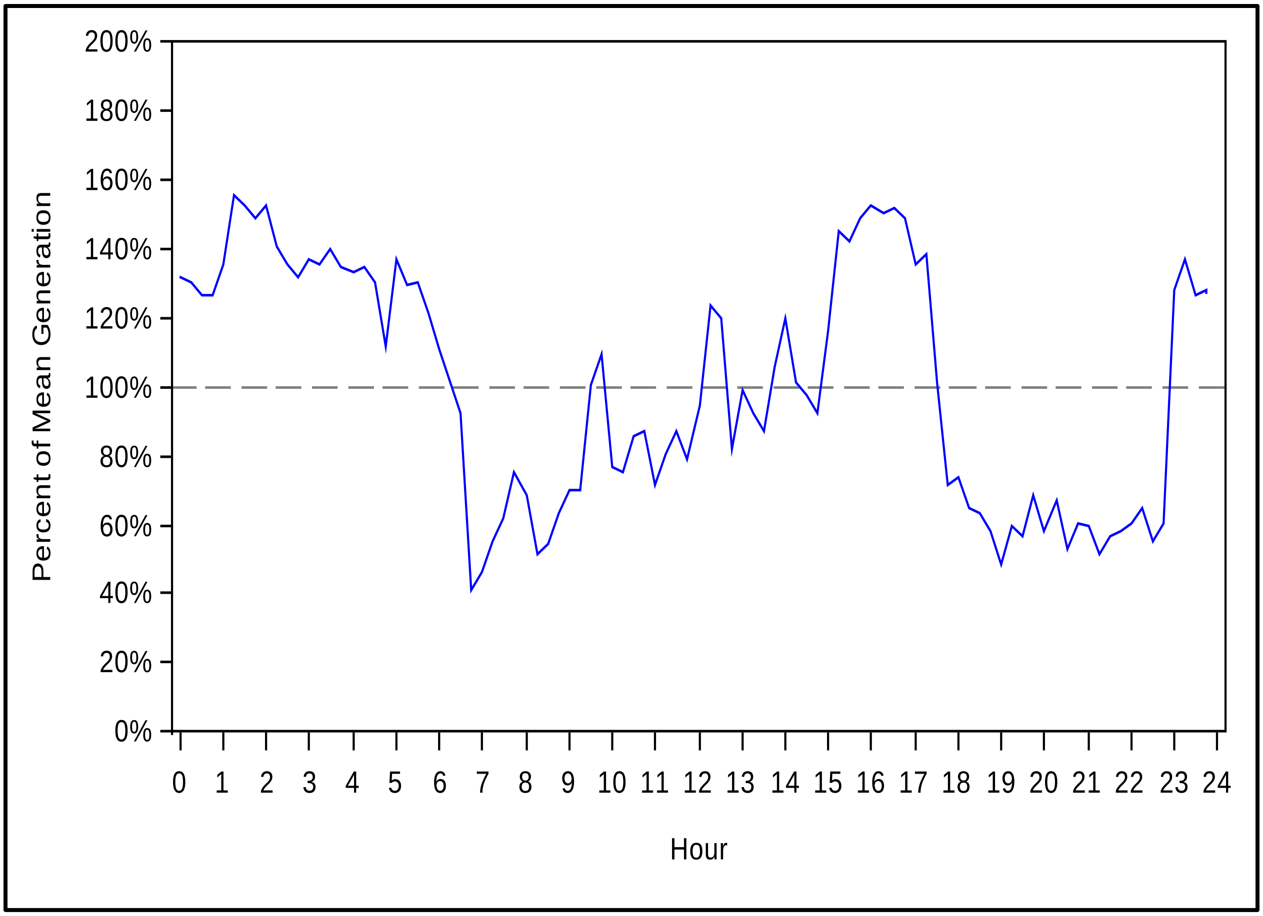
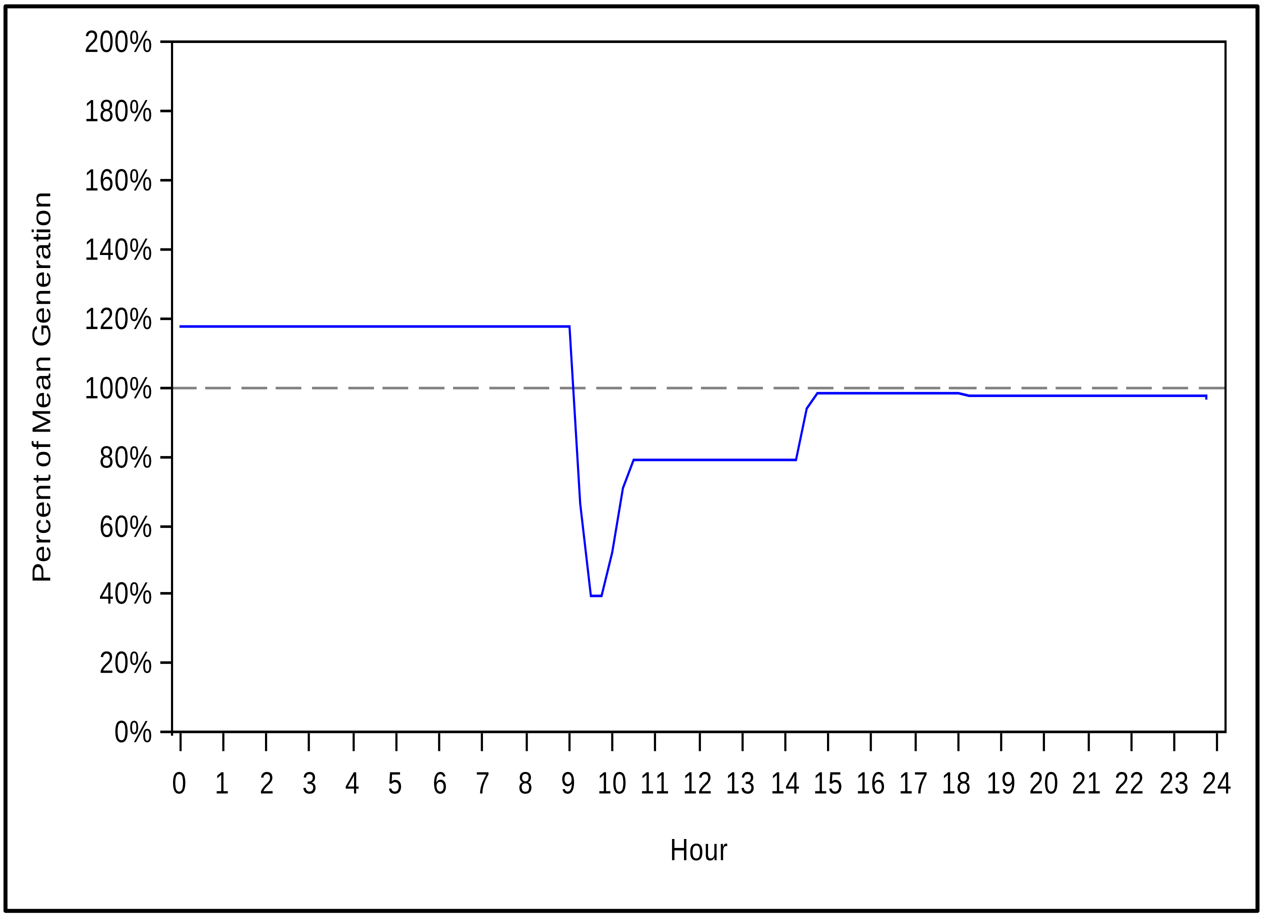


**Figure B-2: Example of a Non-Volatile Load Day—Generation as Percent of Daily Mean**



Since Figure B-1 and Figure B-2 only show a single day, as examples of what these profiles look like over a wider range of days, Figure B-3 and Figure B-4 show the loads for the same sites for the entire month of June. Figure B-3 shows that the volatility seen in the single day is even more evident, with some observations approaching 200% of the daily mean. In Figure B-4, the lack of volatility is also consistent, with a clustering of days that show almost no deviation from the mean output. Note that while there are many days where the load drops to zero, these observations are excluded from the calculation of the mean because they would show changes in load that likely have nothing to do with a unit's attempt to meet site demand.

**Figure B-3: Example of a Volatile Load, All June Days—Generation as Percent of Daily Mean**

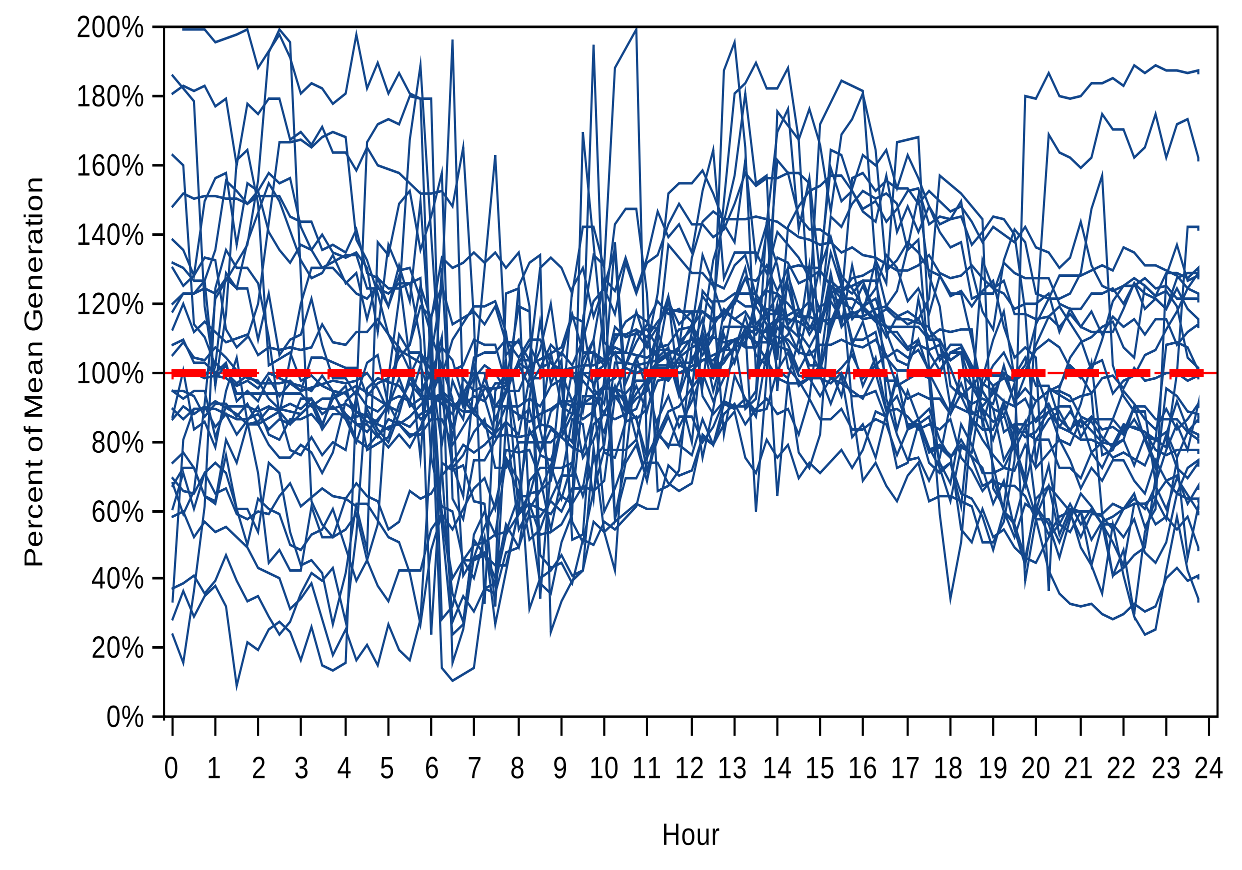
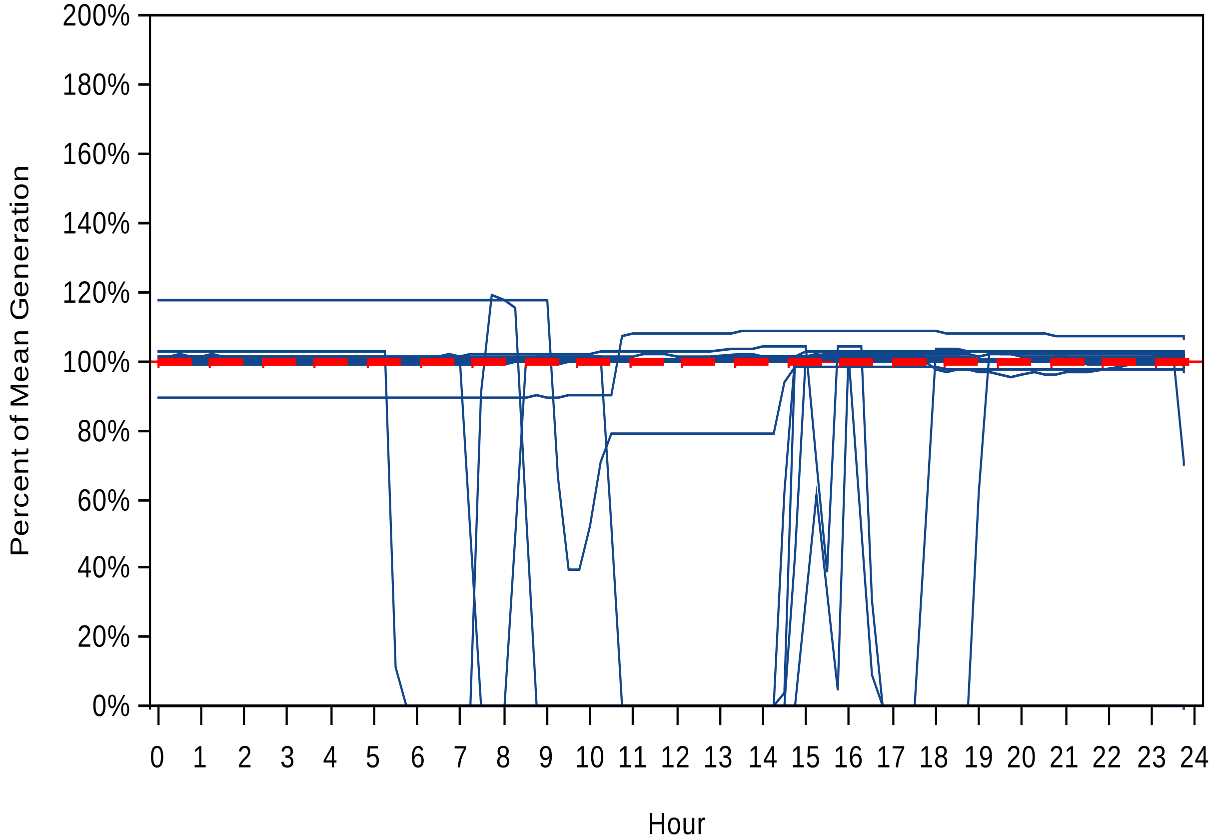


**Figure B-4: Example of a Non-Volatile Load, All June Days—Generation as Percent of Daily Mean**




Having selected the deviation from the non-zero mean as the metric, the next step is to develop systematic rules or criteria to classify each site's generation profile. The selection of these criteria comes down to two questions. First, how much does an observation have to deviate from the mean to be considered a sign of volatility? Second, how often must these deviations occur for a site to be considered non-baseload? Once the criteria are established, a site that has a certain percentage of observations that deviate from the daily mean by a given percentage will be classified as non-baseload. All other sites that fail to meet the criteria will be classified as baseload. To select these criteria, the approach was to assign sites as non-baseload based on multiple levels for each criterion and then evaluate the resulting distributions to see which set of criteria produced the most reasonable results. Each site was classified based on five levels for size of deviation and five levels for the frequency of occurrence. For both criteria, the levels were 10%, 20%, 30%, 40%, and 50%, so each site was classified as baseload or non-baseload 25 times.

The count of sites and percent of total classified as baseload using the five thresholds for both the size of deviation and the frequency of occurrence are presented in Table B-3 for each of the four technologies.

**Table B-3: Counts of Sites Classified as Baseload Generation Profiles by Size of Deviation and Percent Occurrence by Technology Type**

| | | Percent Occurrence | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | GT 10% | | GT 20% | | GT 30% | | GT 40% | | GT 50% | |
| **Technology** | **Size of Deviation** | **Sites** | **Percent of Total** | **Sites** | **Percent of Total** | **Sites** | **Percent of Total** | **Sites** | **Percent of Total** | **Sites** | **Percent of Total** |
| Fuel Cell | 10% off Mean | 7 | 47% | 13 | 87% | 15 | 100% | 15 | 100% | 15 | 100% |
| | 20% off Mean | 11 | 73% | 15 | 100% | 15 | 100% | 15 | 100% | 15 | 100% |
| | 30% off Mean | 14 | 93% | 15 | 100% | 15 | 100% | 15 | 100% | 15 | 100% |
| | 40% off Mean | 14 | 93% | 15 | 100% | 15 | 100% | 15 | 100% | 15 | 100% |
| | 50% off Mean | 15 | 100% | 15 | 100% | 15 | 100% | 15 | 100% | 15 | 100% |
| Gas Turbines | 10% off Mean | 4 | 80% | 4 | 80% | 4 | 80% | 4 | 80% | 4 | 80% |
| | 20% off Mean | 4 | 80% | 5 | 100% | 5 | 100% | 5 | 100% | 5 | 100% |
| | 30% off Mean | 5 | 100% | 5 | 100% | 5 | 100% | 5 | 100% | 5 | 100% |
| | 40% off Mean | 5 | 100% | 5 | 100% | 5 | 100% | 5 | 100% | 5 | 100% |
| | 50% off Mean | 5 | 100% | 5 | 100% | 5 | 100% | 5 | 100% | 5 | 100% |
| IC Engine | 10% off Mean | 36 | 47% | 48 | 63% | 57 | 75% | 64 | 84% | 69 | 91% |
| | 20% off Mean | 46 | 61% | 64 | 84% | 70 | 92% | 71 | 93% | 72 | 95% |
| | 30% off Mean | 63 | 83% | 71 | 93% | 72 | 95% | 74 | 97% | 74 | 97% |
| | 40% off Mean | 70 | 92% | 73 | 96% | 74 | 97% | 75 | 99% | 75 | 99% |
| | 50% off Mean | 70 | 92% | 73 | 96% | 75 | 99% | 75 | 99% | 76 | 100% |
| Microturbine | 10% off Mean | 31 | 58% | 40 | 75% | 45 | 85% | 48 | 91% | 49 | 92% |
| | 20% off Mean | 46 | 87% | 48 | 91% | 50 | 94% | 50 | 94% | 50 | 94% |
| | 30% off Mean | 49 | 92% | 50 | 94% | 50 | 94% | 51 | 96% | 51 | 96% |
| | 40% off Mean | 50 | 94% | 50 | 94% | 51 | 96% | 51 | 96% | 52 | 98% |
| | 50% off Mean | 50 | 94% | 51 | 96% | 51 | 96% | 52 | 98% | 53 | 100% |

The establishment of the thresholds was in large part a data-driven exercise and this matrix was the starting point for selecting a set of criteria for the final classification. First, these data helped to narrow down the analysis by identifying unnecessary threshold levels. For example, larger percent deviation thresholds rarely resulted in non-baseload classifications, which was not consistent with visual reviews of the load profiles, so they are clearly too conservatives. At the other end, the 10% deviation from the mean occurring 10% of the time resulted in nearly half of the fuel cells classified as non-baseload, which is inconsistent with how that technology is used. Once the criteria were restricted, the next step was to visually inspect plots for those sites that were sensitive to changes in the criteria to determine which results made the most sense. While this approach does introduce some subjectivity into the analysis, the vast majority of the sites were clearly one or the other, so only a few sites on the margin were subject to this bias.

After a review of the sites that were marginal in terms of their classification, the final criteria selected for load classification were the 20% or greater deviations from the mean occurring at least 20% of the time. Using these criteria, the final counts for the classified load profiles by technology, location, and type of site are shown in Table B-4. Note that of the original 196 sites, the analysis excluded 46 that had exclusively zero values for the four summer months.[1] There were no sites with fuel cells or gas turbines classified as non-baseload using these criteria and overall 89% of the sites were classified as baseload.

**Table B-4: Counts of Final Load Profiles Classified by Technology**

| | | | Load Profile | | |
|---|---|---|---|---|---|
| **Technology** | **Location** | **Site Type** | **Baseload** | **Non-Baseload** | **Total** |
| Fuel Cell | Coastal | Occupancy | 7 | 0 | 7 |
| | | Process | 1 | 0 | 1 |
| | Inland | Occupancy | 3 | 0 | 3 |
| | | Process | 4 | 0 | 4 |
| | | *Total* | *15* | *0* | *15* |
| Gas Turbines | Coastal | Process | 3 | 0 | 3 |
| | Inland | Occupancy | 1 | 0 | 1 |
| | | Process | 1 | 0 | 1 |
| | | *Total* | *5* | *0* | *5* |
| IC Engine | Coastal | Occupancy | 22 | 4 | 26 |
| | | Process | 8 | 2 | 10 |
| | Inland | Occupancy | 22 | 1 | 23 |
| | | Process | 12 | 5 | 17 |
| | | *Total* | *64* | *12* | *76* |
| Microturbine | Coastal | Occupancy | 17 | 2 | 19 |
| | | Process | 10 | 1 | 11 |
| | Inland | Occupancy | 15 | 1 | 16 |
| | | Process | 6 | 1 | 7 |
| | | *Total* | *48* | *5* | *53* |
| | | **Grand Total** | **132** | **17** | **149** |

[1] While it would require additional research to know the actual reason why these sites had no generation during the summer months, there are many possible reasons, including systems that have reached the end their useful life, absence of a qualified operator, or facilities that are now vacant.

As an indicator of how robust these classifications were, Table B-5 shows the percentage of individual days that were classified consistently with the final load profile. With the exception of fuel cells, the sites classified as baseload all had a more than 90% of their individual days classified consistently. For the sites classified as non-baseload, the share of individual days classified in a consistent manner was not as high, but the results still show that most sites fit clearly into one of the two profile types when using the 20% deviation occurring 20% of the time criteria.

**Table B-5: Mean Percent of Days Classified by Technology**

| | Classified Load Profile | |
|---|---|---|
| **Technology** | **Baseload** | **Non-Baseload** |
| Fuel Cell | 88.4% | NA |
| Gas Turbines | 97.7% | NA |
| IC Engine | 92.8% | 72.7% |
| Microturbine | 95.1% | 86.2% |

A comparison of the baseload and non-baseload profiles is presented in a series of plots below. Figure B-5 and Figure B-6 show the baseload and non-baseload profiles for coastal and inland locations, respectively. Figure B-7 and Figure B-8 show the load profiles for process- and occupancy-based site types. The figures present the generation profiles in terms of mean capacity factors to put them on an equivalent scale with vertical ticks showing the 99% confidence limits. The important aspects of these graphs are the shape and the variability in capacity factors associated with type of load profile. Any comparison of the magnitude of the capacity factors comes with a couple of key caveats. First, the load profiles are comprised of sites with different technologies that may have different operating characteristics, so the difference in capacity factors could be driven by the contributing sites. Second, the number of sites included in each mean load profile varies considerably, with some of the non-baseload profiles consisting of only a few sites. For example, with the occupancy-based sites in Figure B-8, the non-baseload profile is based on eight sites, while the baseload profile has data from 87 sites.

In general, non-baseload generation profiles shown in Figure B-5, Figure B-6, Figure B-7, and Figure B-8 exhibit two characteristics that distinguish them from the baseload profiles. First, they show a clear rise during the daytime hours, likely associated with the increase in DG output to meet a site's increased demand due to occupancy- and weather-related factors. This is particularly clear in Figure B-5, which shows the mean capacity factors for coastal locations, and Figure B-8, which shows the mean capacity factors for occupancy-based sites. Second, the non-baseload generation profiles show more variability in their mean hourly capacity factors, as seen in the vertical ticks that represent the 99% confidence intervals. This is clearly visible in all four figures, where the baseload generation profiles have much narrower confidence bands around the mean capacity factor values.

**Figure B-5: Mean Generation Capacity Factors for Baseload and Non-Baseload, Coastal**

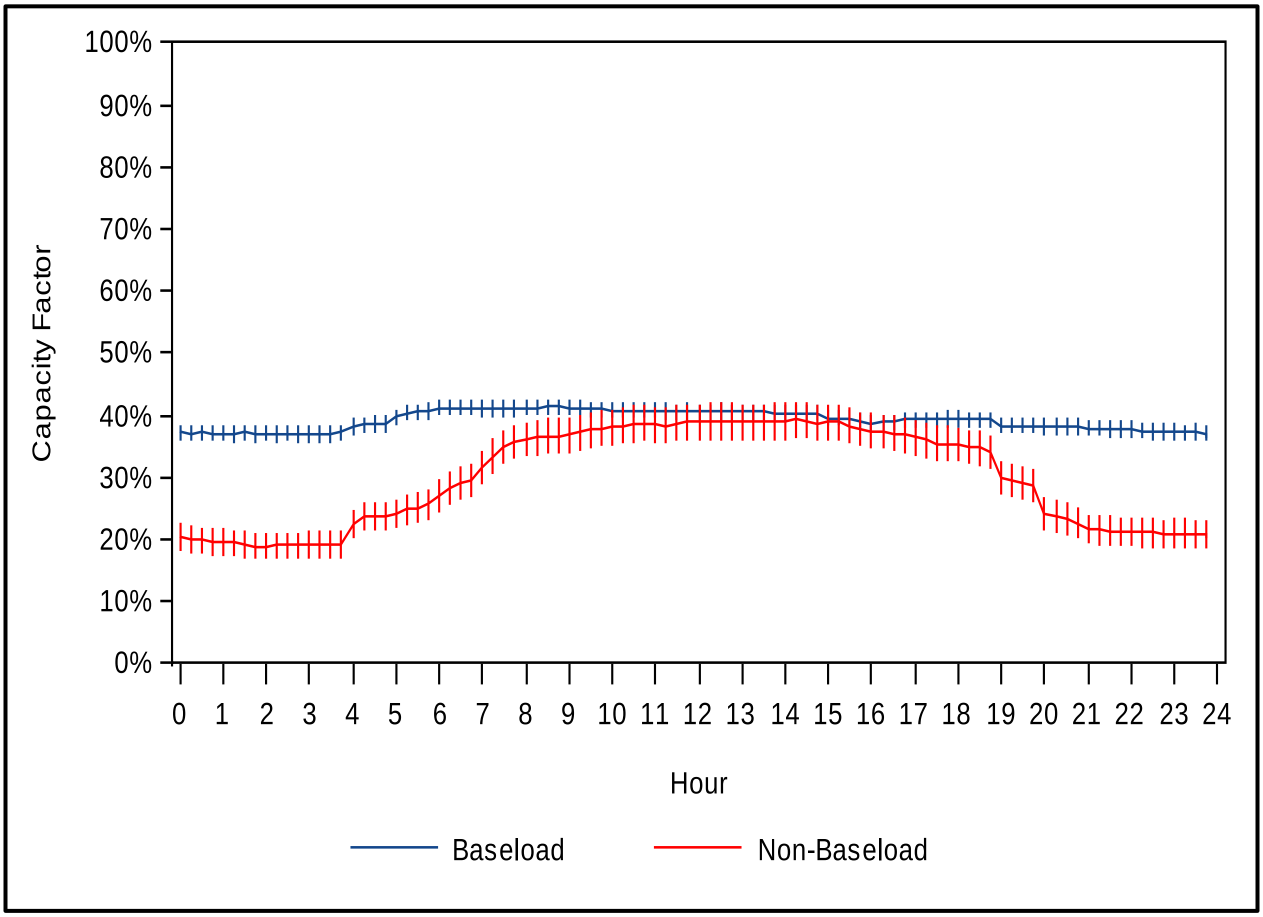


**Figure B-6: Mean Generation Capacity Factors for Baseload and Non-Baseload, Inland**

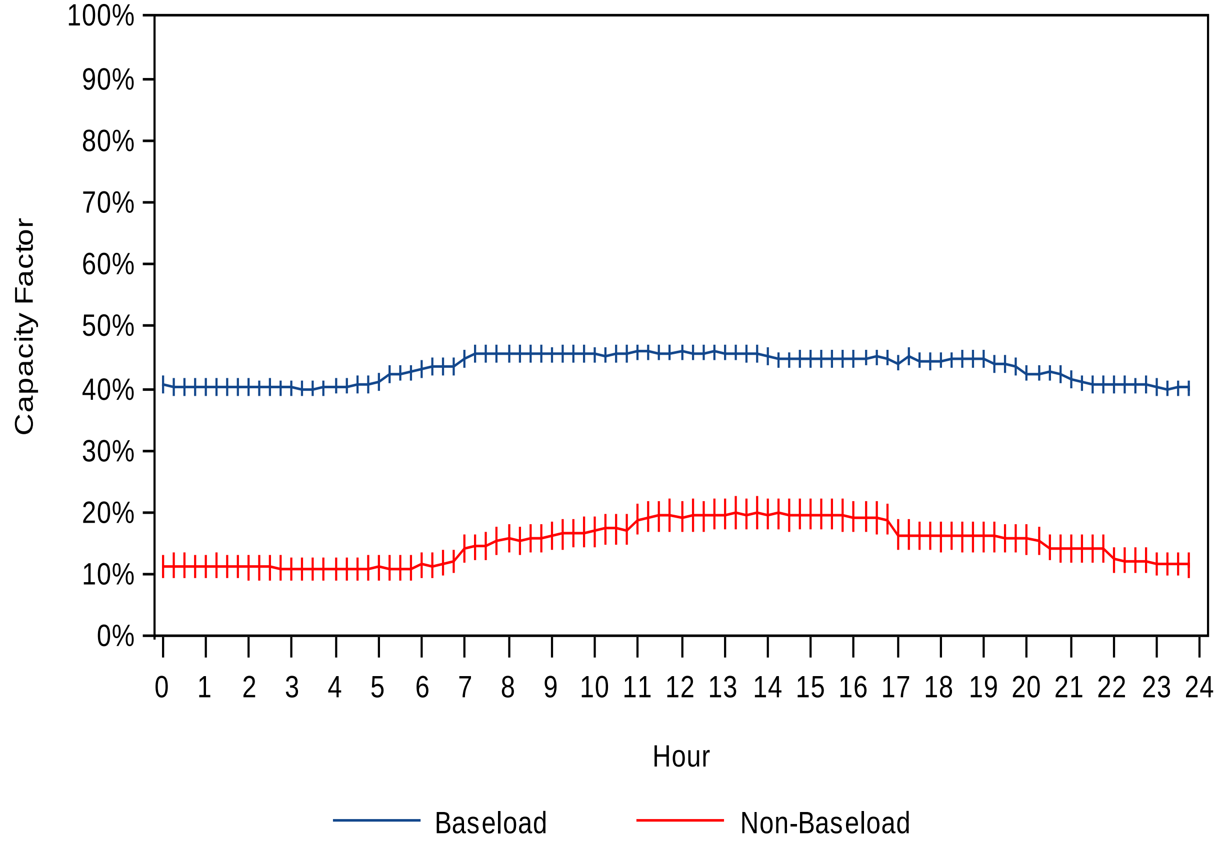


**Figure B-7: Mean Generation Capacity Factors for Baseload and Non-Baseload, Process Sites**

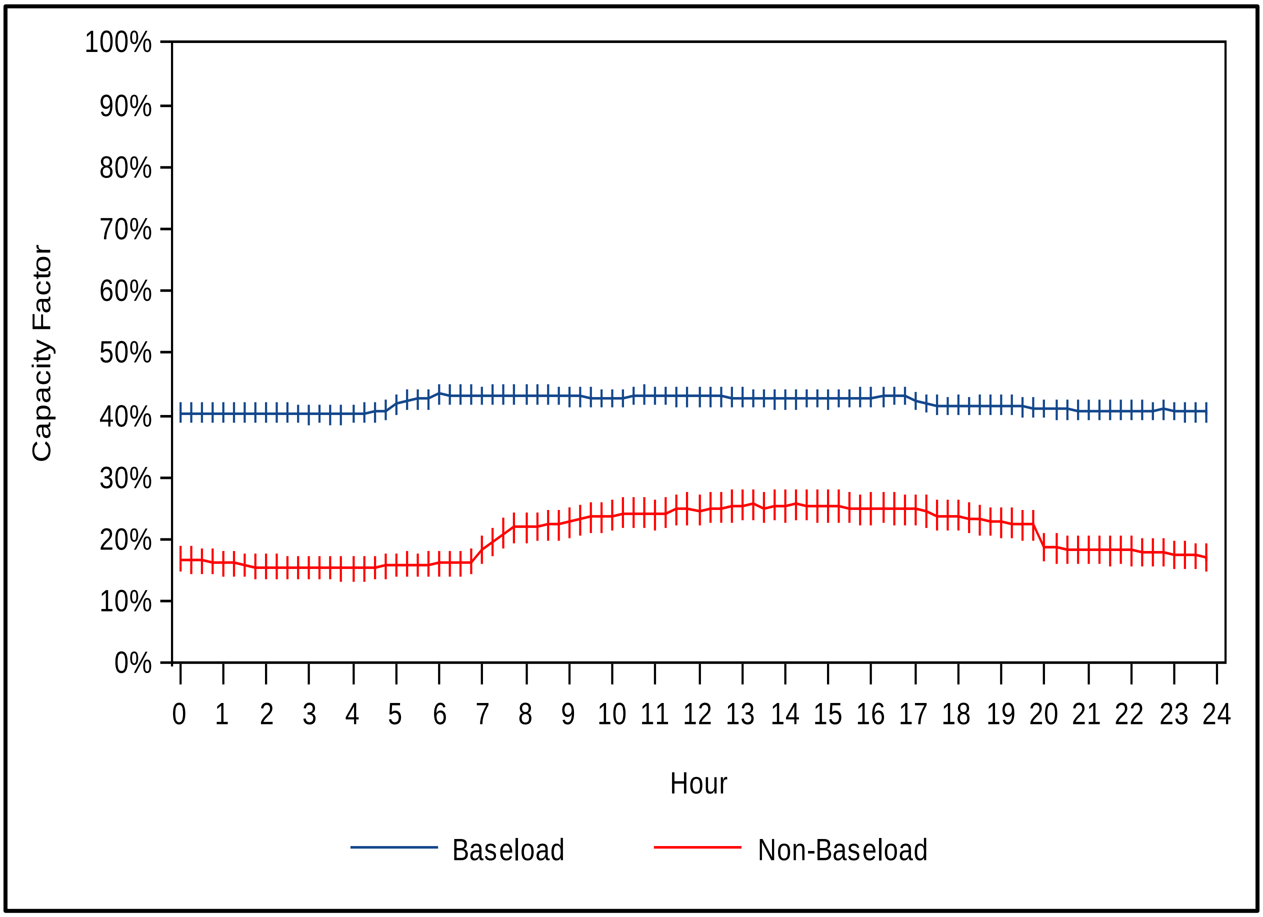
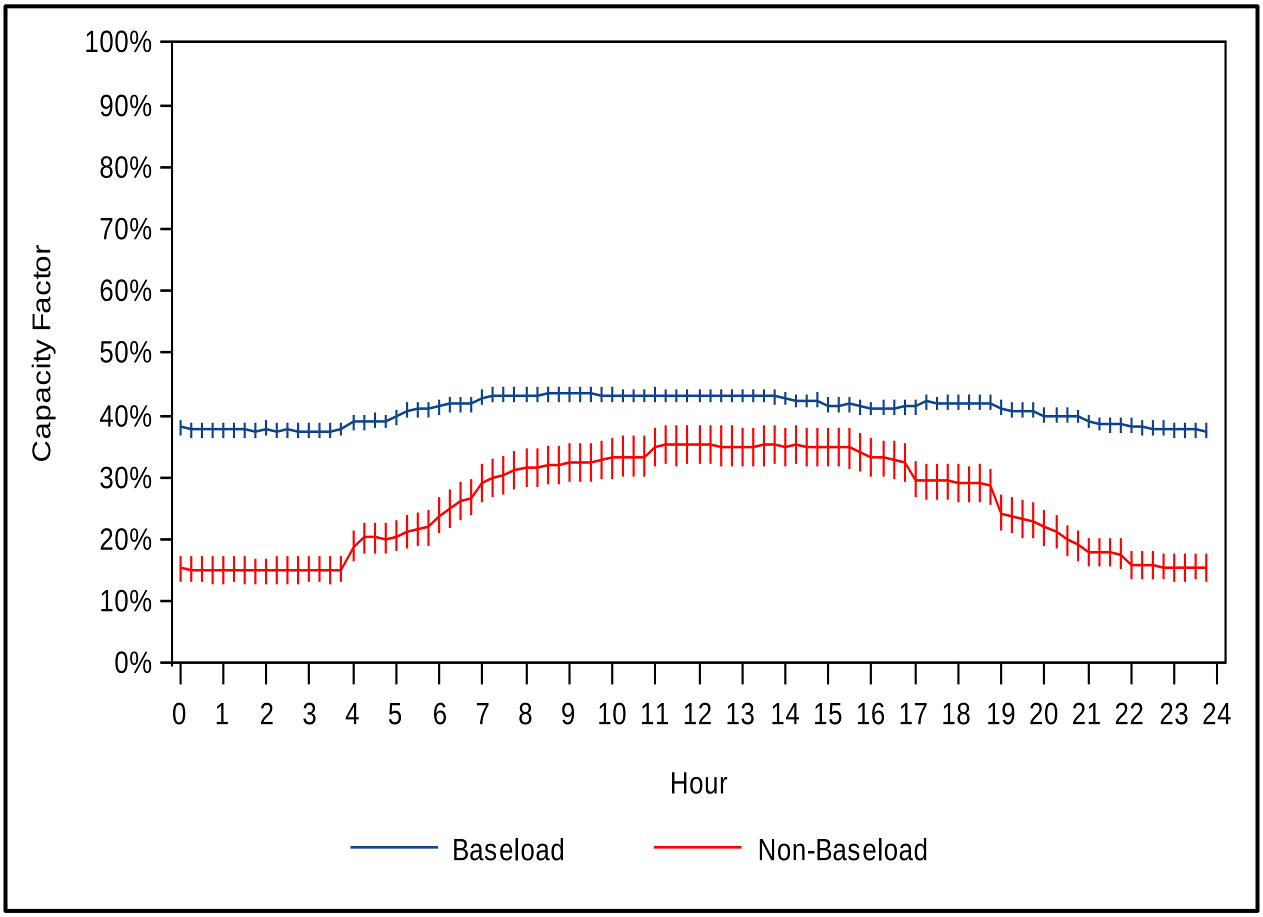


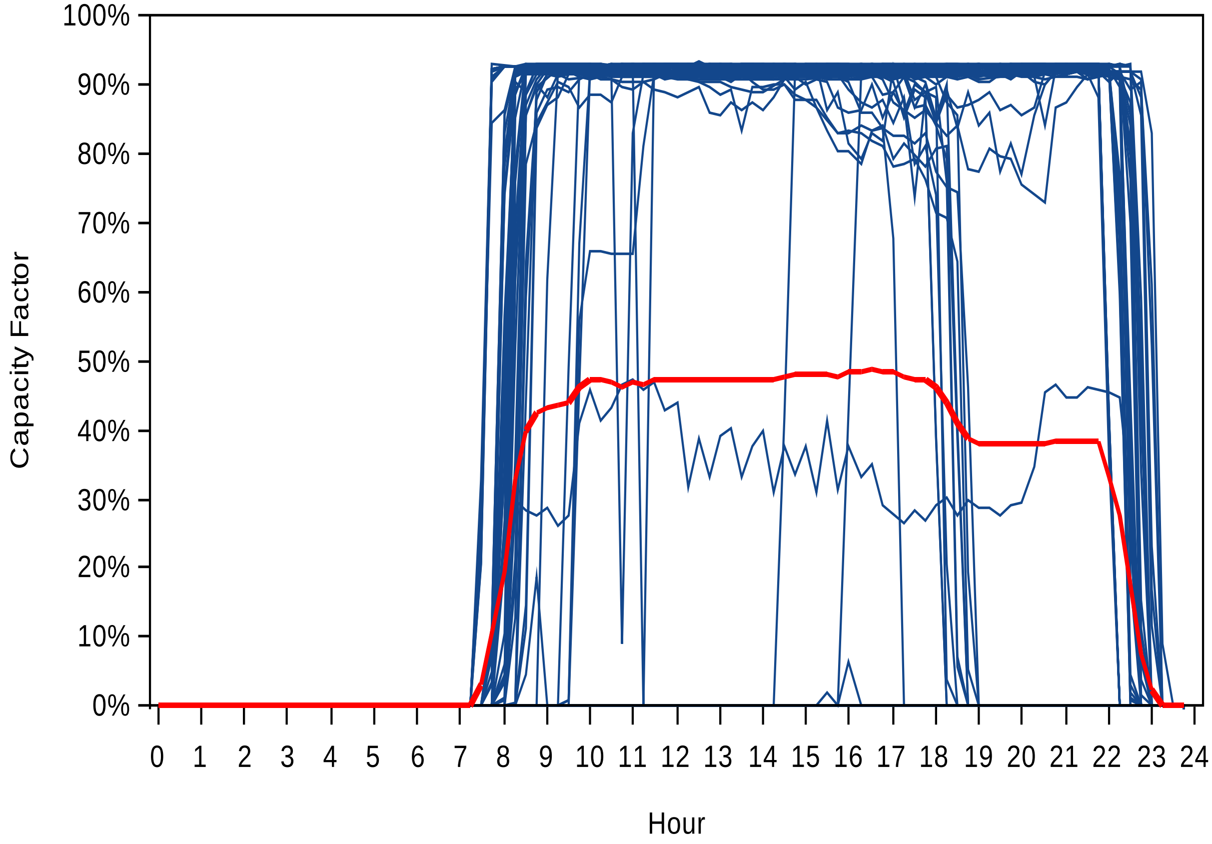
**Figure B-8: Mean Generation Capacity Factors for Baseload and Non-Baseload, Occupancy Sites**




Because mean generation profiles combine data for multiple sites, they can often hide the actual variability associated with DG and provide a false understanding of how much generation actually fluctuates on both a daily and hourly basis. As an alternative to the mean generation profiles, another step in the analysis was the selection of four representative generation profiles to show typical DG utilization from individual sites. These four generation profiles were selected for implementation in the cost-effectiveness analysis.

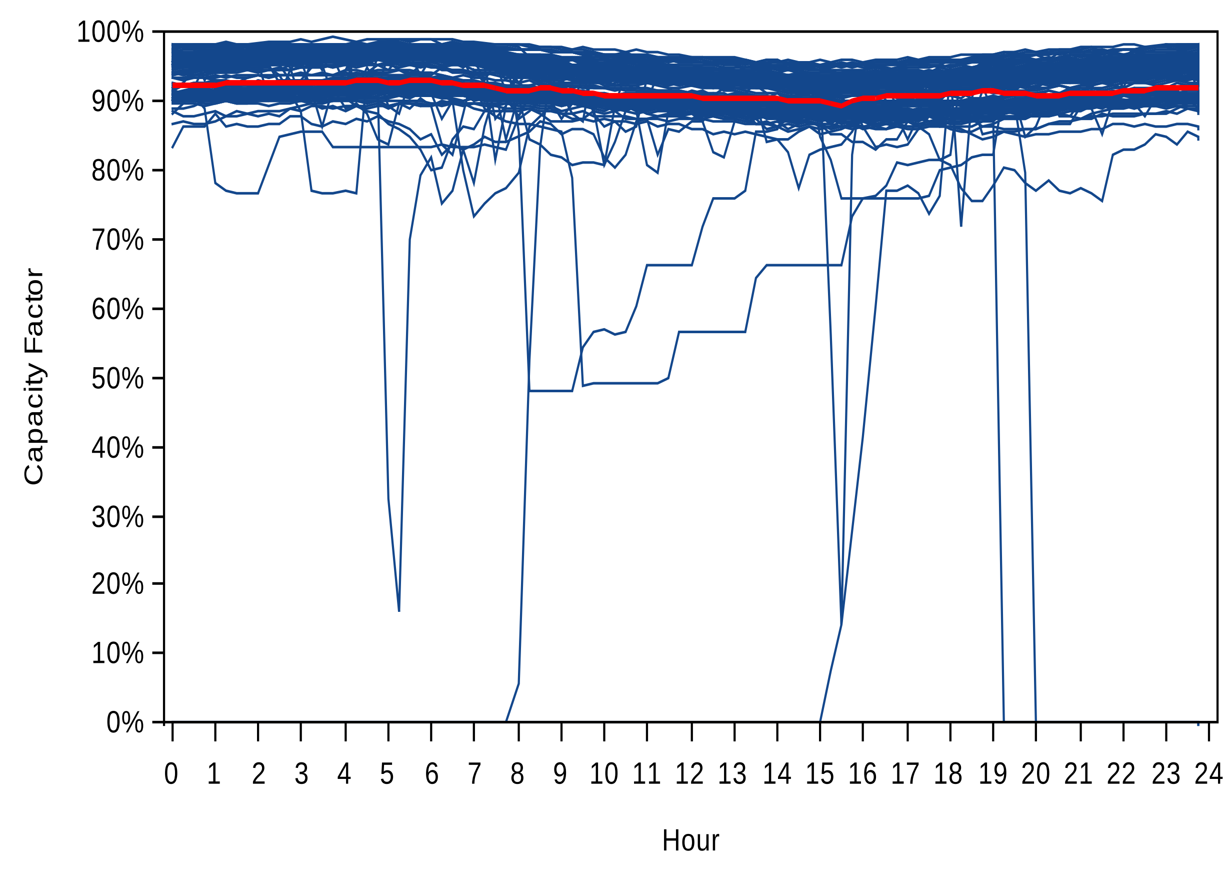
The four types of typical generation profiles include two baseload profiles and two non-baseload profiles. The two baseload profiles are presented in Figure B-9 and Figure B-10, which show the hourly capacity factors for all days along with the mean value. The first represents a baseload unit that operates during the day but shuts down during what are presumably non-business hours. There is a step down in the mean capacity factor in the evening that is likely associated with different operation schedules on some days. The mean capacity factor, which is around 50% of the unit's typical level on days when it is actually operation, shows that the unit is only used on around half of the days.

**Figure B-9: Typical Baseload Generation Profile, Partial Day Operation**



The second typical baseload generation profile is a unit that operates 24 hours per day on most days. As seen in Figure B-10, the mean capacity factor is very close to the middle of the individual daily profiles, all of which range from around 90% to 100% of the unit's capacity with only a few exceptions.

**Figure B-10: Typical Baseload Generation Profile, 24-Hour Operation**



The two non-baseload typical generation profiles are shown in Figure B-11 and Figure B-12. In the first figure, the load profile suggests a unit that is ramped up as site demand requires but for a site that has a fairly consistent demand profile with a single peak occurring in the early afternoon. The unit never operates at full capacity and the mean capacity factor lies among the individual daily profiles, which indicates that the unit has few off days. The second non-baseload profile shows far less consistent patterns in its daily profiles, both in terms of the general shape and magnitude. As seen Figure B-12, the capacity factors show multiple peaks that occur at all hours, with only a subtle trend towards the early morning and early afternoon hours. On some days, the unit will operate at almost 80% capacity for the most of the day and on others, it will stay around 10%.

**Figure B-11: Typical Non-Baseload Generation Profile, Single Peak**

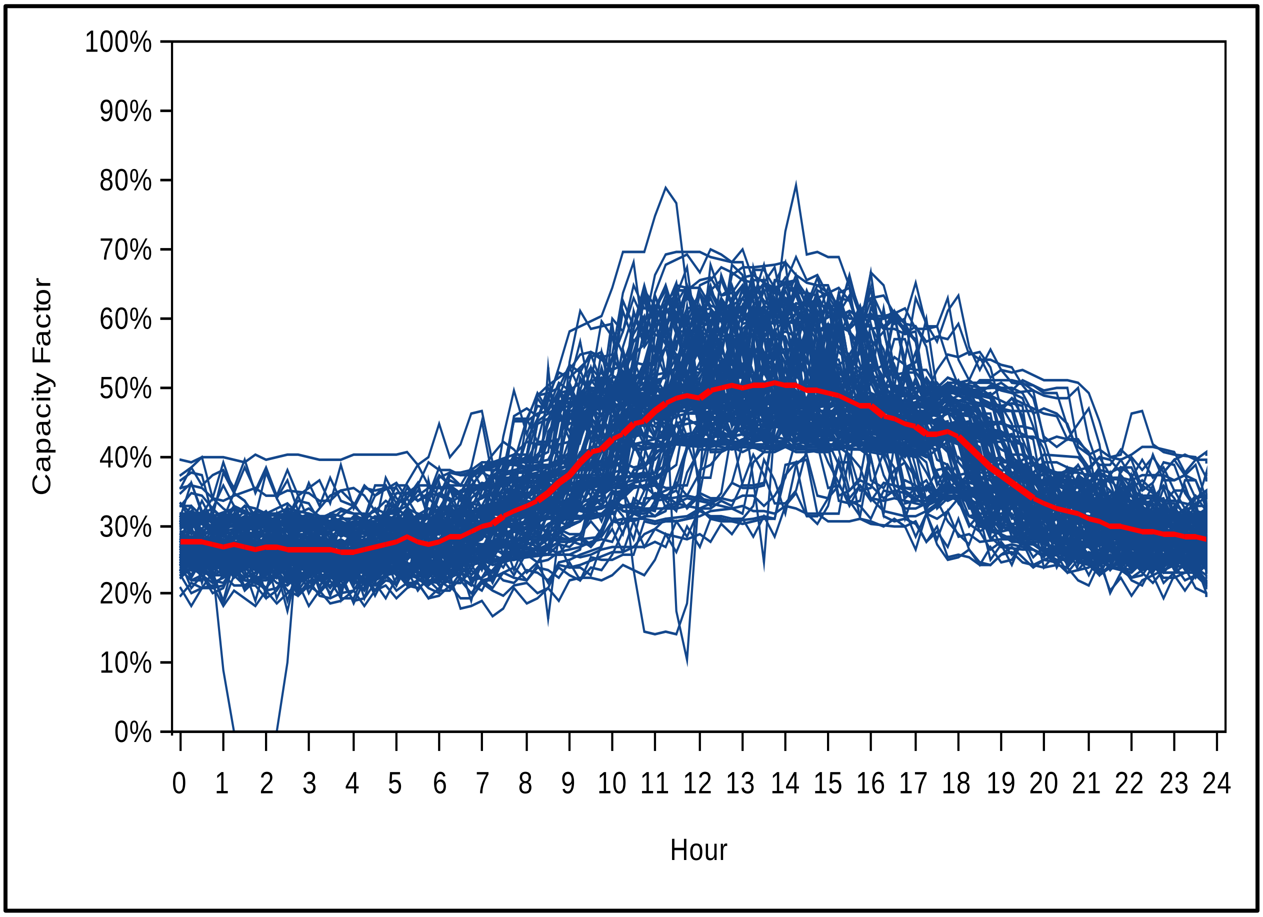
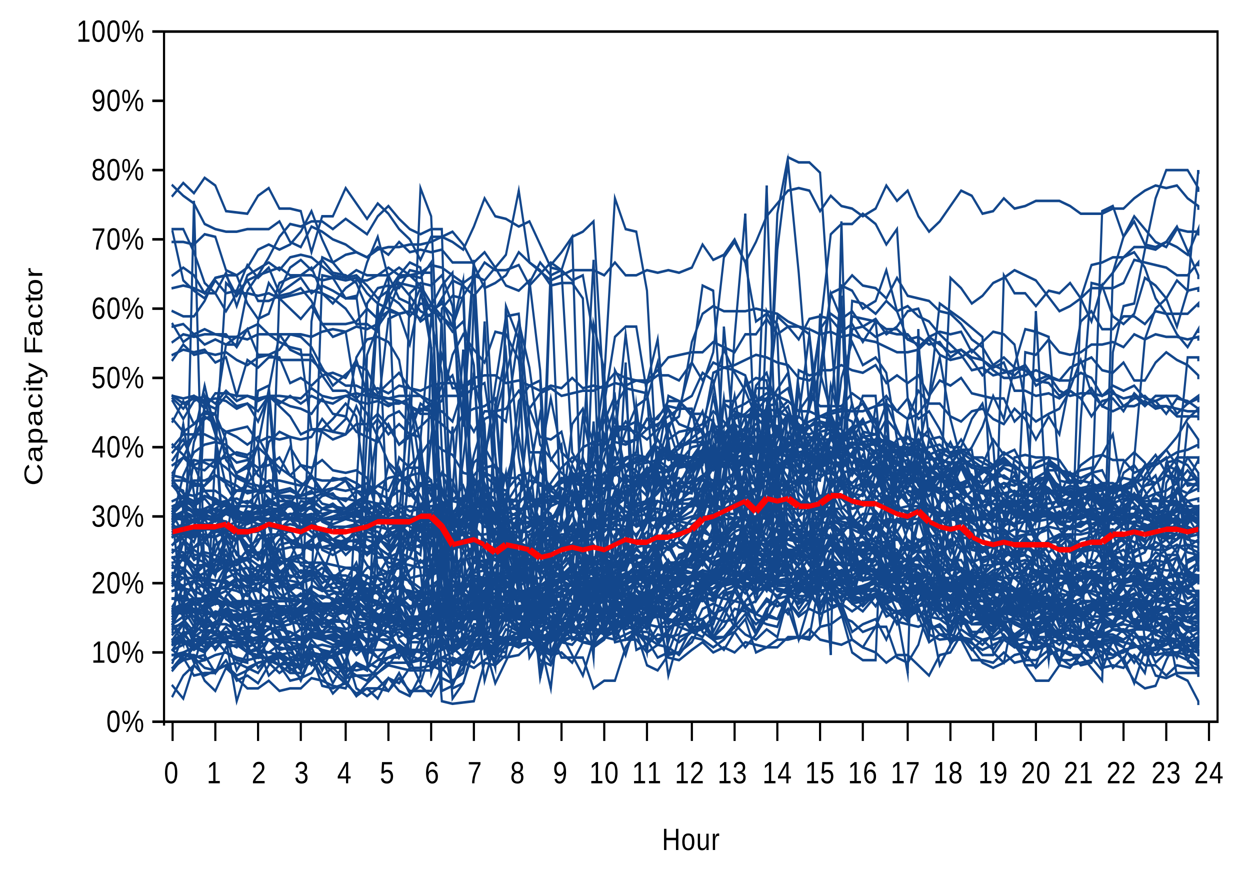


**Figure B-12: Typical Non-Baseload Generation Profile, Multiple Peak**



## B.3 Demand Profiles for Sites with Demand Data

In addition to the data used for generation load profiles, one utility (PG&E) provided site-level demand data for a subset of sites. The count of sites by the location, site type, and the classified generation profile with both demand and generation data are presented in Table B-6.

**Table B-6: Count of Sites with Demand Data**

| | | Generation Load Profile | | |
|---|---|---|---|---|
| **Location** | **Site Type** | **Baseload** | **Non-Baseload** | **Total** |
| Coastal | Occupancy | 5 | 2 | 7 |
| | Process | 1 | . | 1 |
| Inland | Occupancy | 3 | . | 3 |
| | Process | 3 | . | 3 |
| Total | Total | 12 | 2 | 14 |

Although the demand data only represent a small number of sites, they still are still valuable for the exploration of several different areas. First, they allow for exploration of variability in demand profiles at the individual site level. Second, they can be summarized to develop mean demand profiles at varying levels of aggregation. Third, they can be combined with the generation data to see how DG is used to meet overall site demand needs. An additional value of these data is that they serve as a means oft validating the results of the demand profile classification analysis.

### *Site-Level Demand Profiles*

The small number of sites with demand data makes it possible to review all of the individual demand profiles separately. Figure B-13 presents the demand profiles for the inland locations and Figure B-14 and Figure B-15 present the demand profiles the coastal locations. To put the figures on an equivalent scale, the data are normalized to show the demand as a percent of the maximum demand. To show the variance in the demand, the figures include a band showing the range between the 25$^{th}$ and 75$^{th}$ percentiles for the hourly demand values.

Depending on one's interests or needs, the demand profiles reveal a number of discussion topics. For one, the load profiles show that the shape is not the only important attribute. For example, Site #1 (Figure B-14) and Site #6 (Figure B-15) for the coastal locations have what might be called fairly equivalent shapes, but the quartile ranges show that Site #1 operates at a very consistent level with deviations skewed towards higher levels of output. If all one is interested in is overall shape, these two sites are equivalent, but if the day-to-day usage is important they do not belong together.

Another interesting aspect of these demand profiles is that they show that the site type is, in many cases, a reasonable way to group the profiles. While it comes with the caveat that the assignment of these categories is imperfect, the occupancy site profiles are indicative of an operating schedule whereas the process sites tend to be flatter. This is also based on insufficient number of sites to reach any conclusions, but the categories would clearly be worthy of consideration should there be a study with more demand data.

**Figure B-13: Mean Demand as Percent of Maximum Demand by Site, Inland Locations**

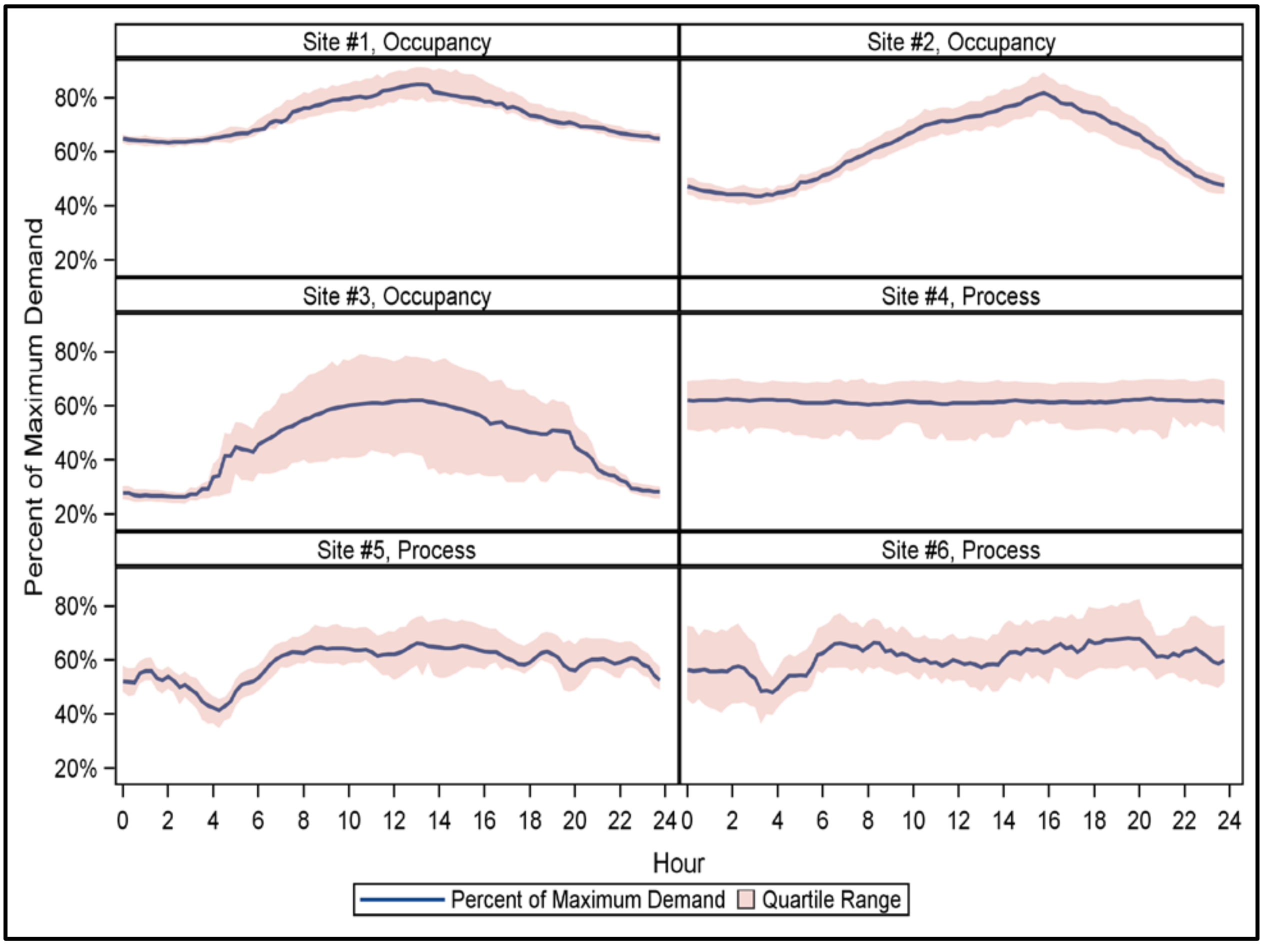


**Figure B-14: Mean Demand as Percent of Maximum Demand by Site, Coastal Locations, Group One**

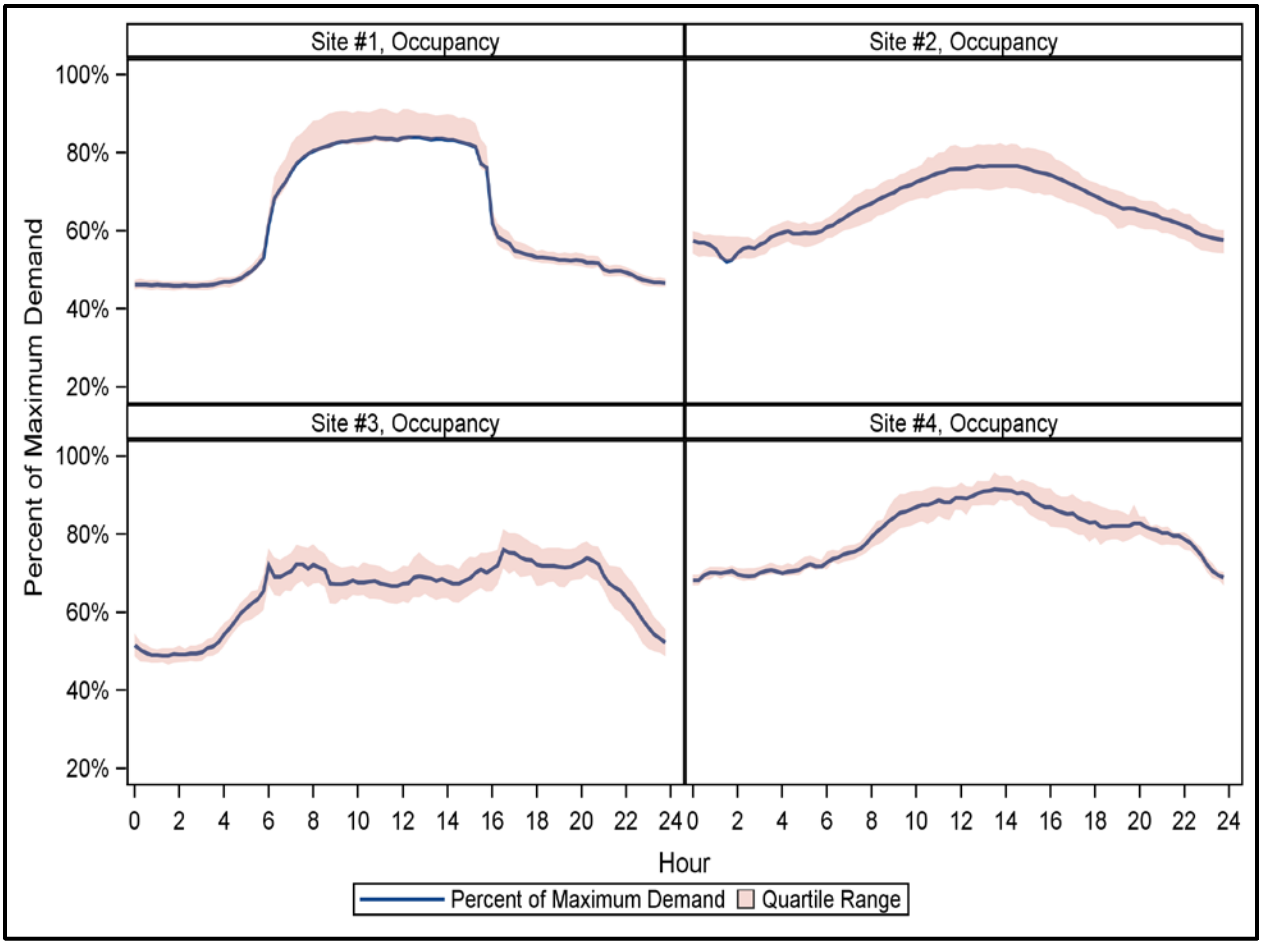
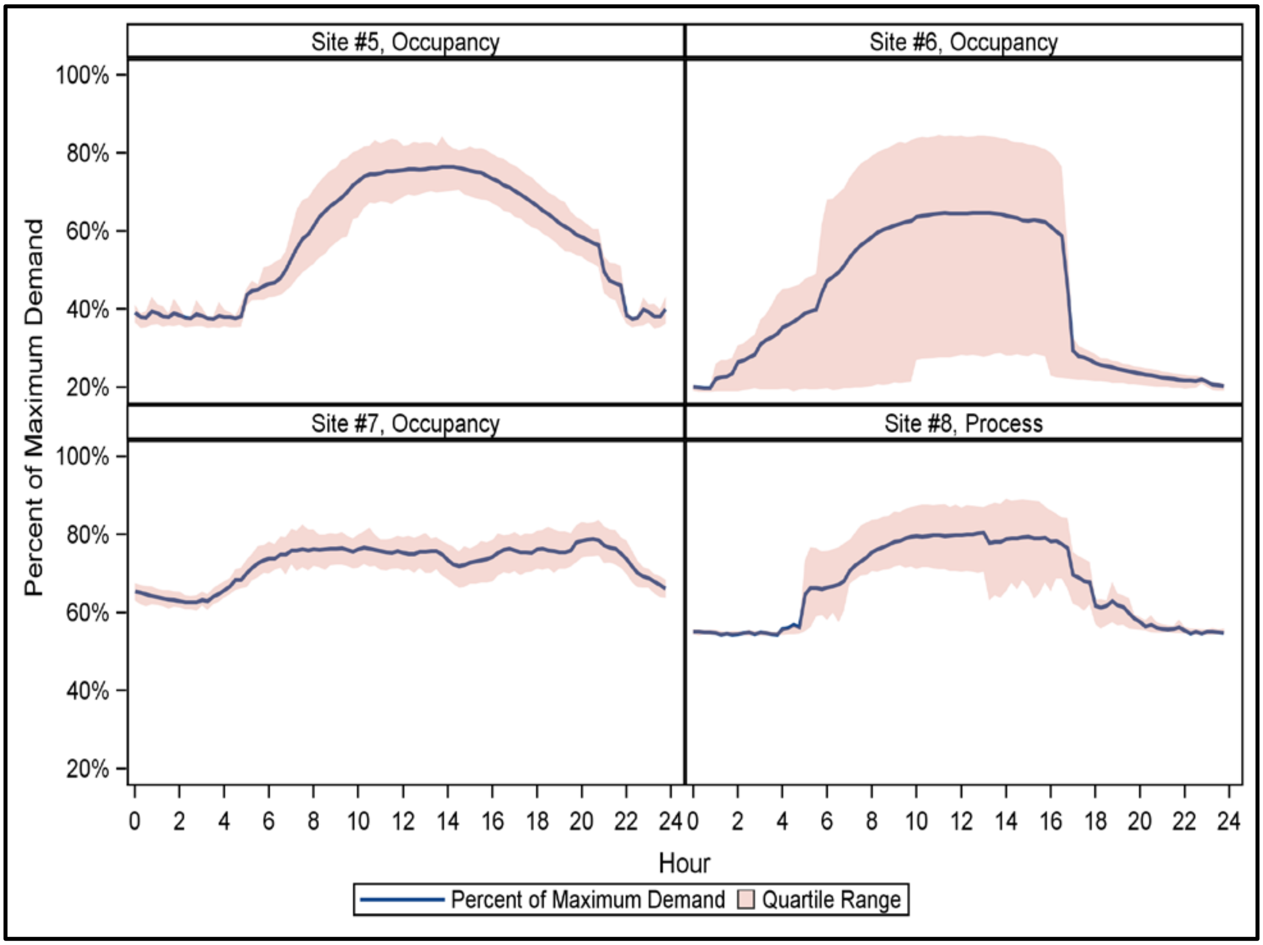


**Figure B-15: Mean Demand as Percent of Maximum Demand by Site, Coastal Locations, Group Two**



One caveat with this analysis is that the total demand values have been calculated as the sum of the provided demand data and the generation data. While the data provided by PG&E was not explicitly documented as net of generation demand, a visual review of the data during the initial diagnostics conclusively demonstrated that the PG&E data was the metered demand, not the total site demand. For example, Figure B-16 shows the daily demand profiles along with the overall mean for the metered demand data provided for PG&E. The mean demand profile shows a small spike in the morning as demand starts to grow and then it drops back down and remains relatively flat until the evening hours when there is a substantial dip in demand. This load profile is already highly unlikely, but when compared to the profile when the generation data are added to the metered demand to create the total demand, as shown in Figure B-17 , it becomes clear that the original data did not include generation. There were enough compelling examples for nearly every site that the generation was added to create the total demand in all cases.

**Figure B-16: Plot of Metered Demand, All Days with Mean**

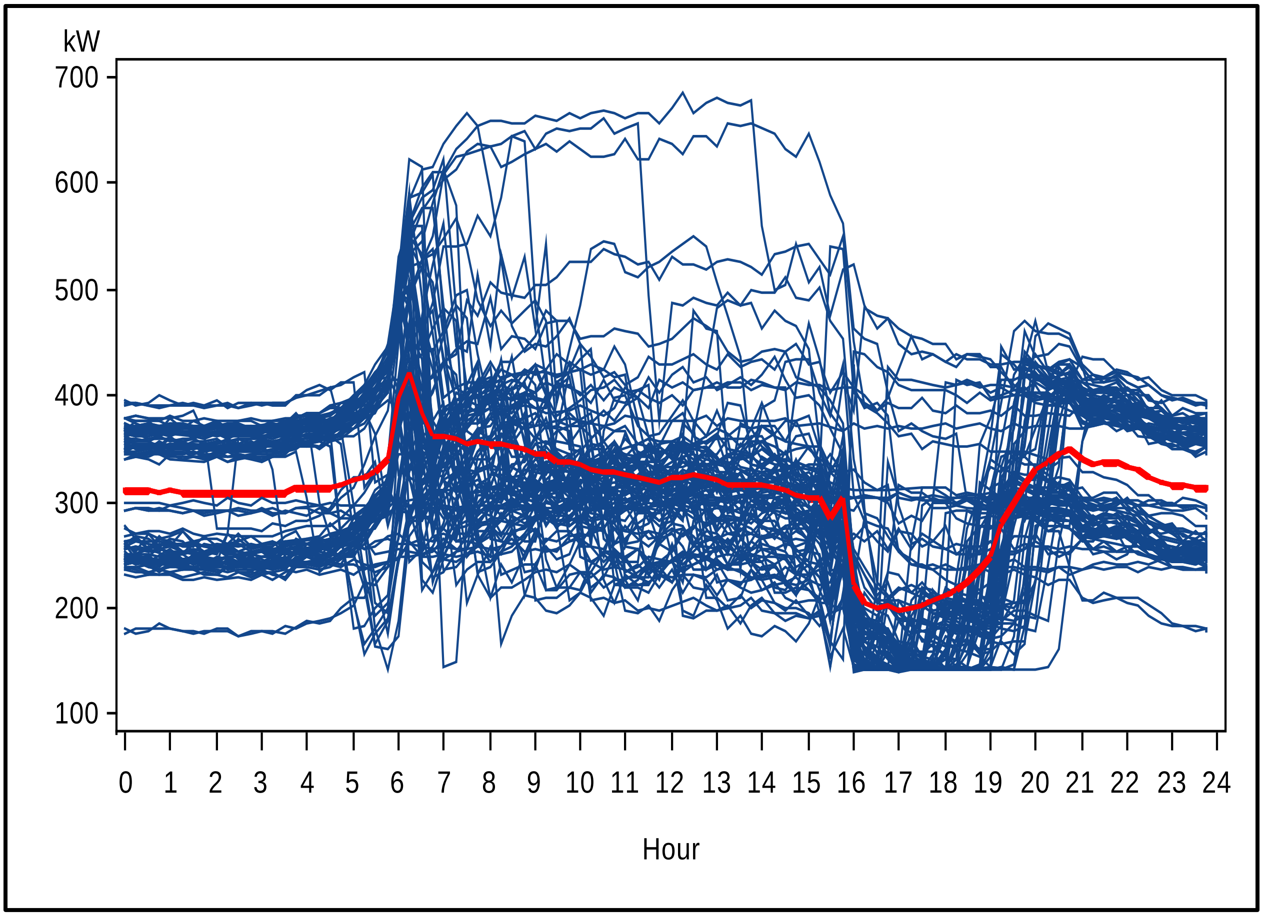
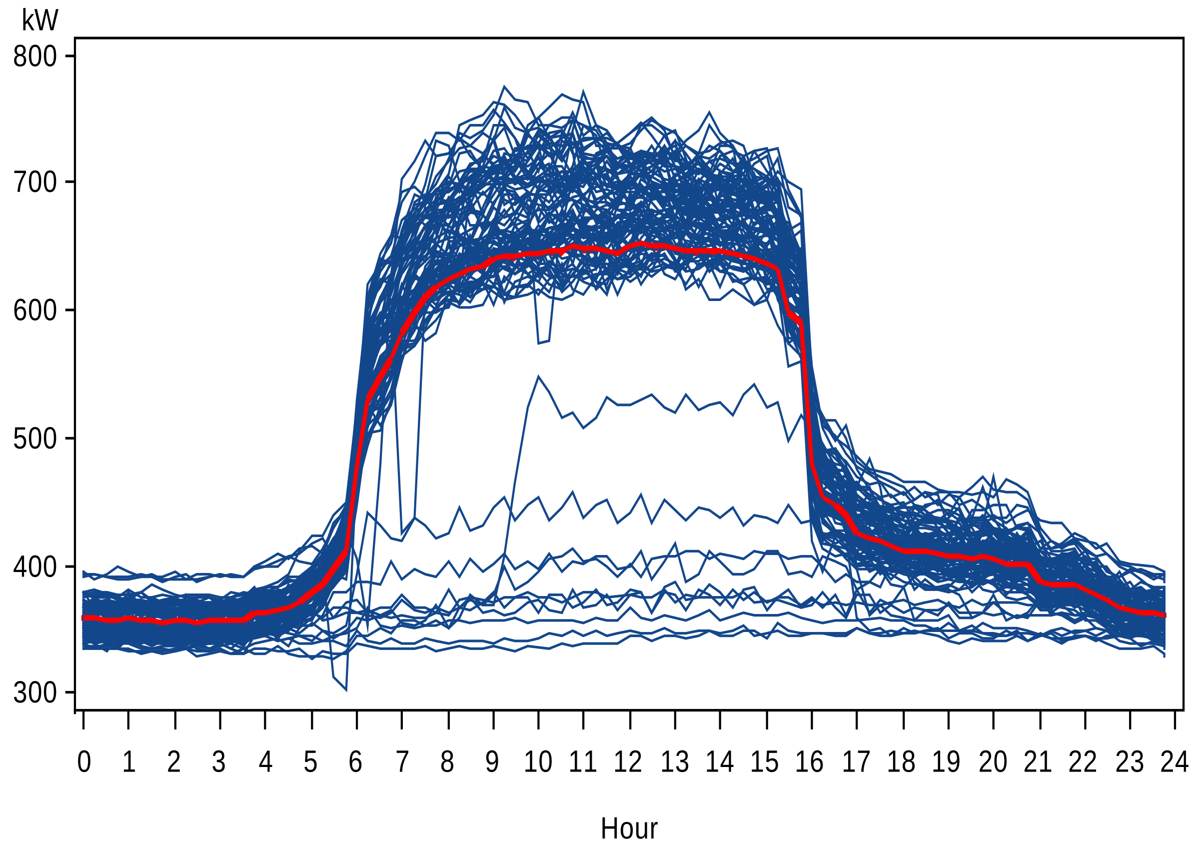


**Figure B-17: Plot of Total Demand, All Days with Mean**



### *Mean Demand Profiles*

As with the generation profiles, the data can be used to calculate mean demand profiles at different levels of aggregation. For example, Figure B-18 and Figure B-19 show the mean demand profiles for coastal and inland locations and occupancy- and process-based sites, respectively. The figures are presented as the percentage of maximum demand to make the profiles more directly comparable, with the 99% confidence limits presented as vertical ticks. These demand profiles are limited in their applicability due to the sample size. For example, the demand profile for coastal locations in Figure B-18 consists of sites that are occupancy-based sites for all but one location, so the shape likely has less to do with the location than facility characteristics. The demand profiles in Figure B-19 are more intuitive, with the process-based sites showing more the more variable demand likely associated with operation schedules.

**Figure B-18: Mean Demand Profiles for Coastal and Inland Locations**

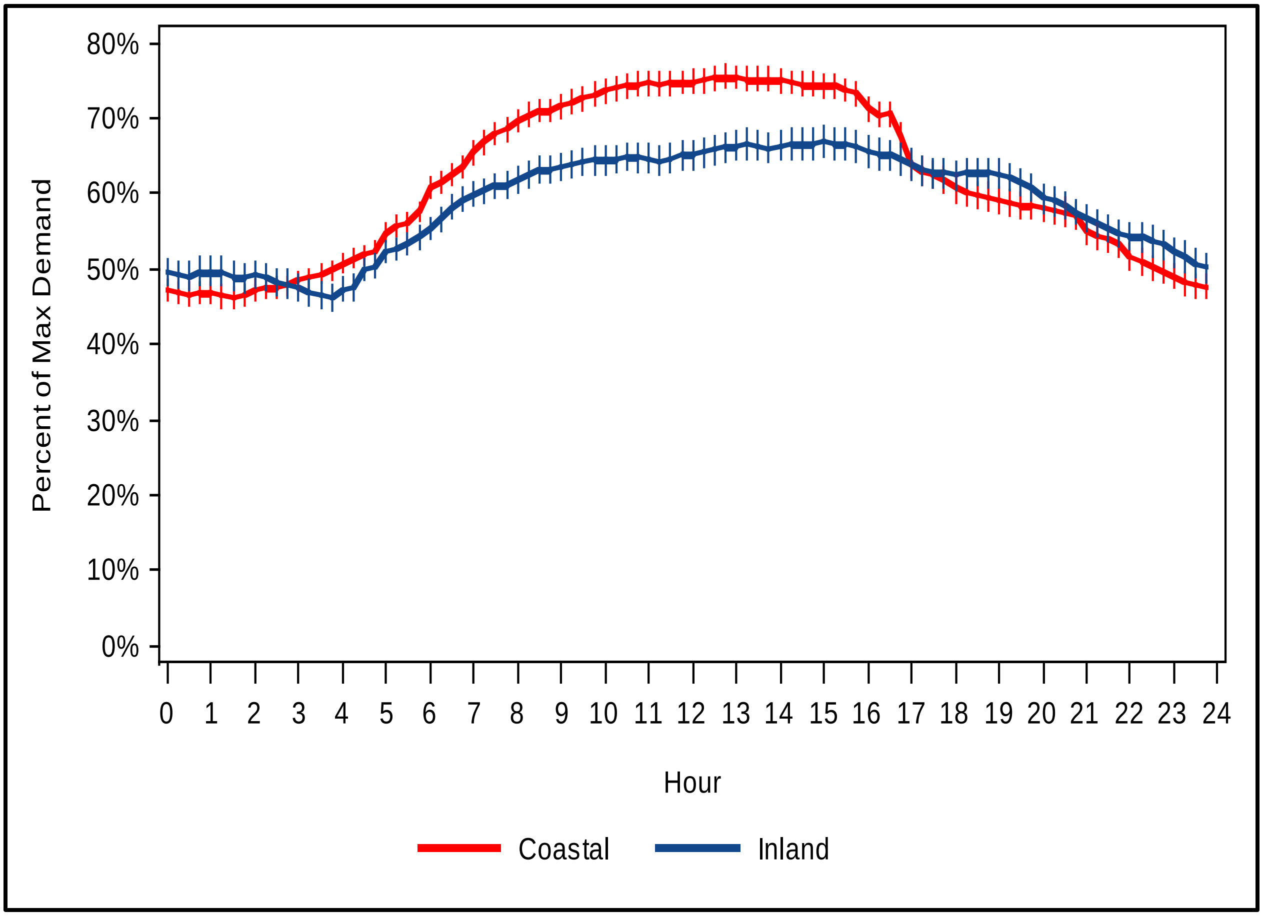
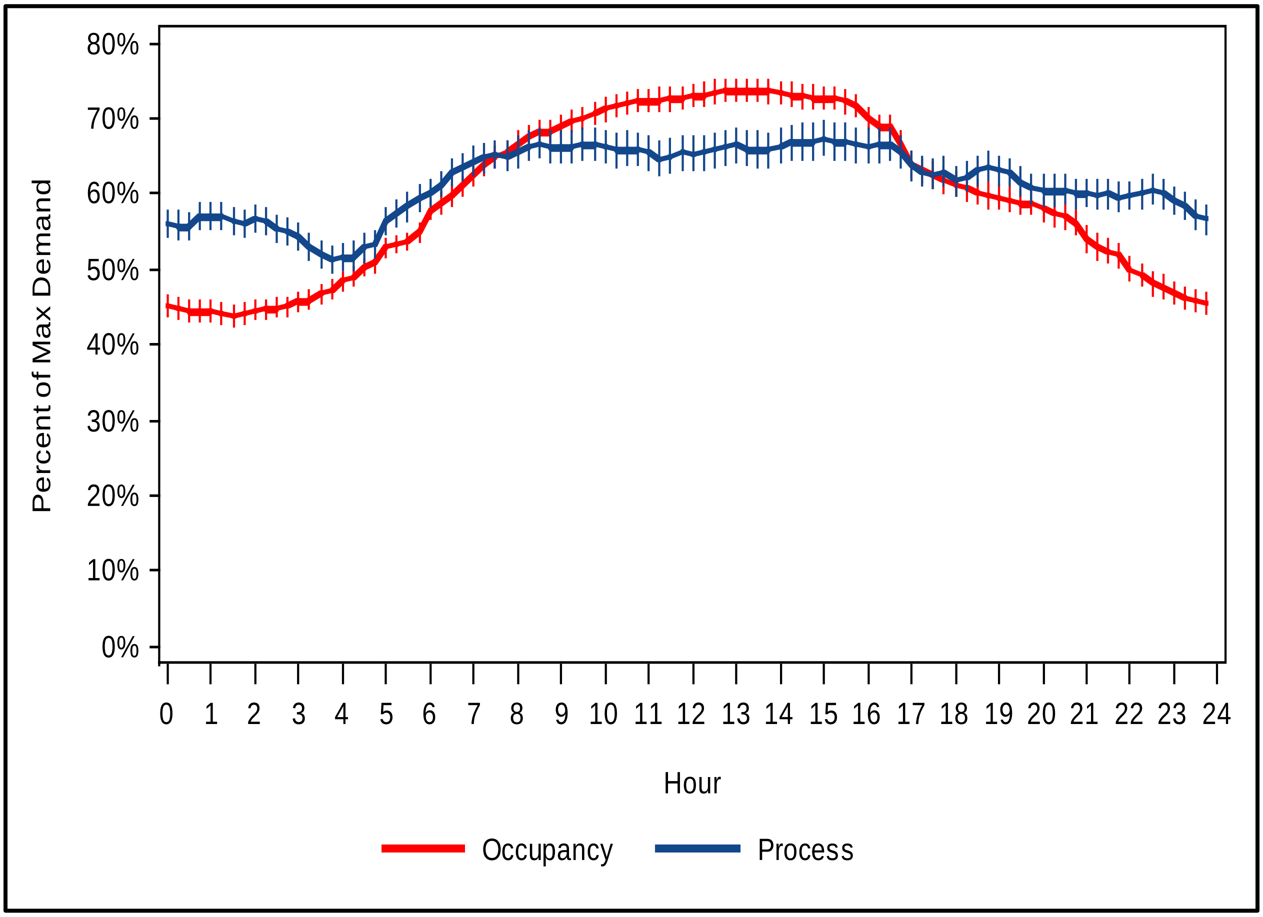


**Figure B-19: Mean Demand Profiles for Occupancy- and Process-Based Sites**

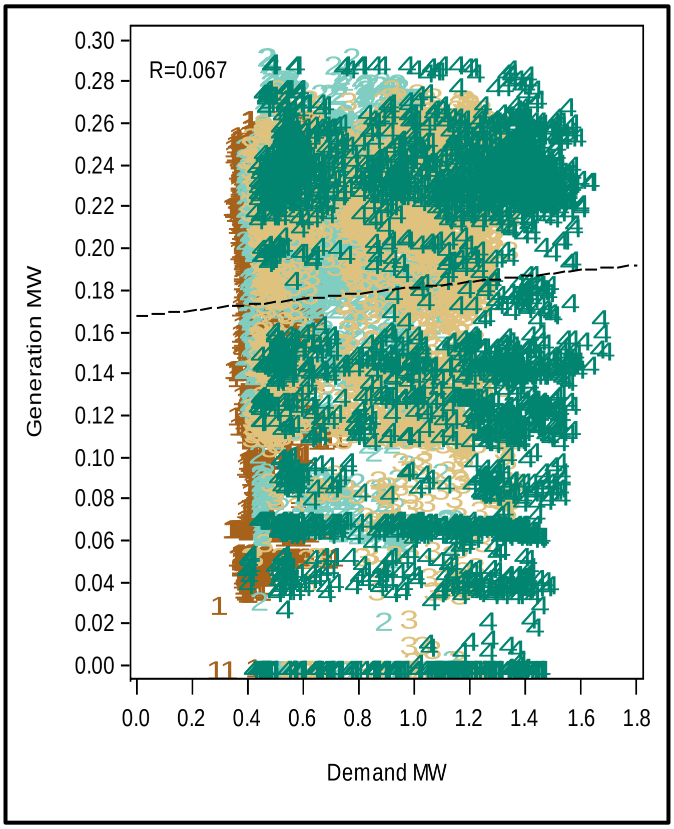



## B.4 Analysis of Generation with Total Site Demand

The availability of demand and generation data offers an opportunity to look at the relationship between DG and overall site demand. One type of analysis that these data allow is an alternative means of classifying whether a site's generation is baseload or non-baseload. A second type of analysis is that the data can show the overall contribution of DG to meeting system demand, which can also show how different technologies are used during times of peak demand.

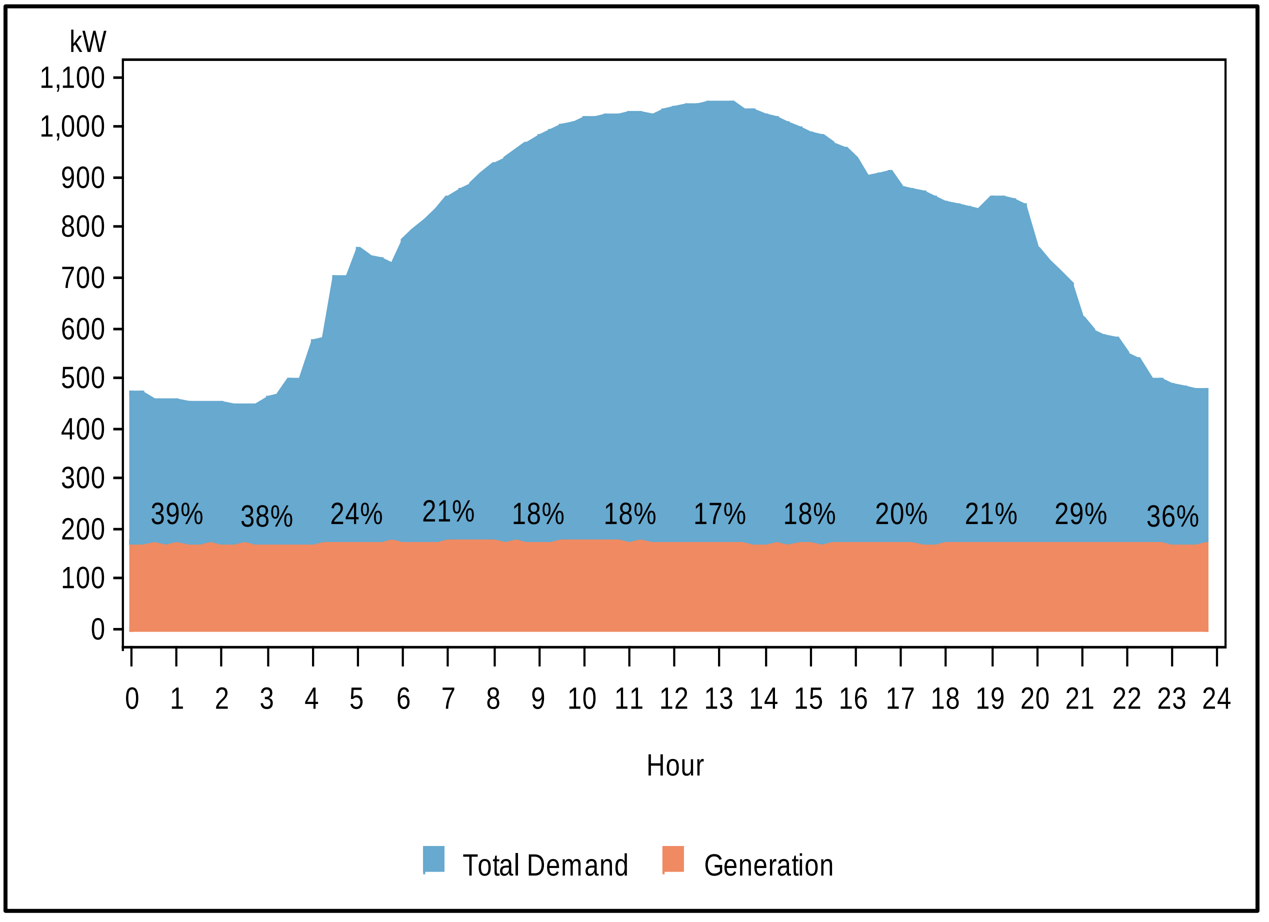
With respect to the first type of analysis, an examination of the correlation between generation and total demand offers an empirical means of determining whether the DG technology is used to meet an increase in demand. Figure B-20 presents a plot of generation by demand for a selected site, with generation plotted as the dependent variable because increasing use of energy is what would cause a site to increase its DG output. The symbols in the plot are numbers one through four, which represent the quartiles for daily maximum demand (four equals the top 25% of daily peaks), so you can whether there is a different relationship on days when demand at the site is higher or lower. As additional details, the correlation is provided in the upper right and the line associated with the linear regression equation is imposed over the data points. The correlation associated with these data is 0.067, which means there is a weak relationship between generation and demand. The data points lie in a rectangular shape, with no pattern showing increased generation with higher levels of site demand. The demand quartiles show no particular pattern beyond the normal dispersal that one would expect to see. As a visual demonstration of the low correlation, the regression line lies almost flat.

**Figure B-20: Scatter of Generation and Demand by Maximum Demand Day Quartiles, Low Correlation**



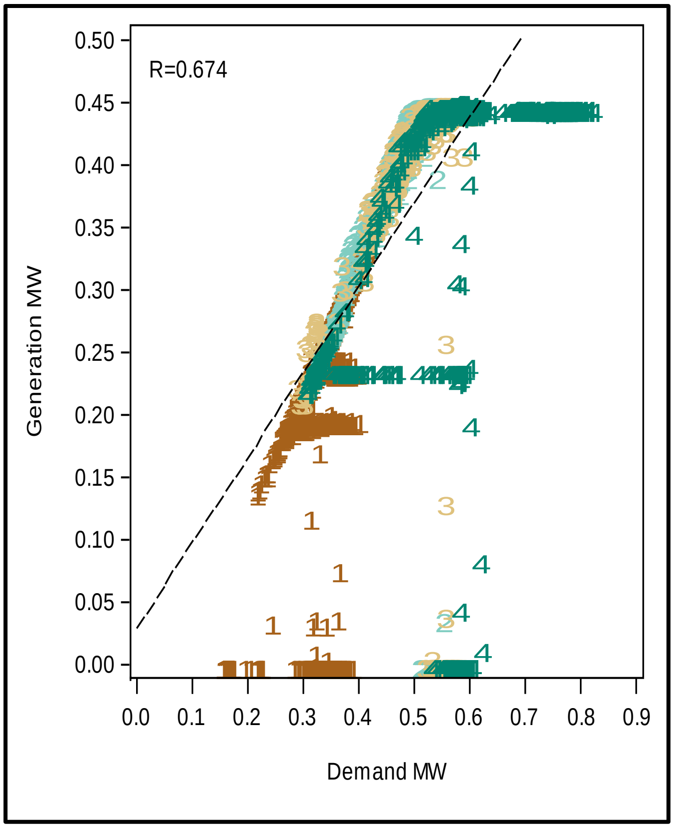
As an alternative illustration of the lack of relationship between generation and demand, Figure B-21 shows the mean hourly values for these variables. The percentage of total demand met by generation, which is annotated for odd hours, declines as the demand increases and the DG output remains fairly constant, which provides further evidence that the site represents a baseload profile.

**Figure B-21: Mean Hourly Generation and Total Demand, Low Correlation**



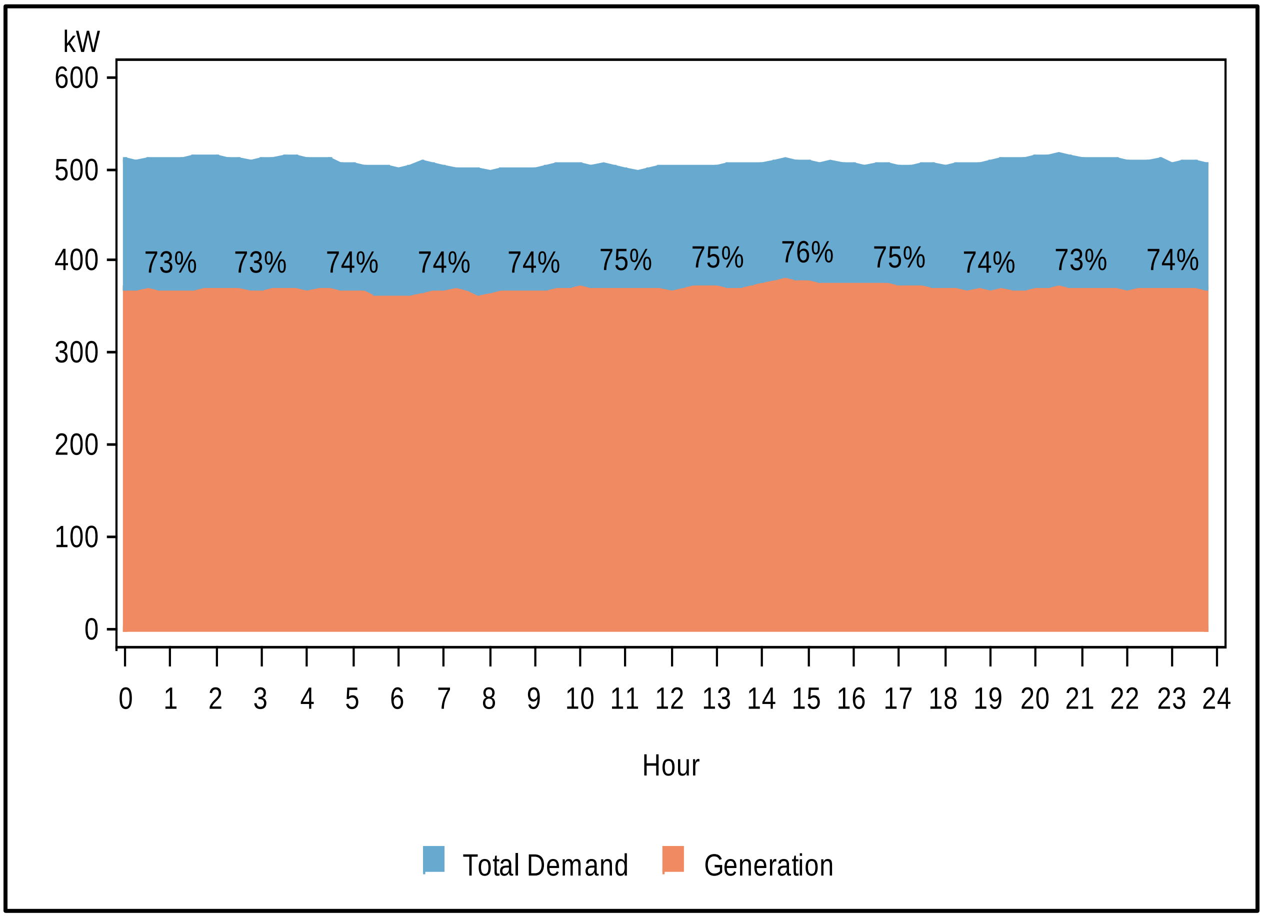
In contrast to the example presented above, two cases are presented below for sites where demand and generation do exhibit a strong relationship. Figure B-22 and Figure B-23 present a scatter plot of generation and demand and the hourly mean values, respectively, for the first high correlation case. The data in Figure B-22 represent a correlation of 0.674 and the generation shows a nearly linear increase as demand goes up until it flattens out at around 0.44 MW, likely when the DG unit has reached its capacity. The symbols for quartiles associated with peak demand days are also separated into fairly discrete groups on the plot, showing that the DG unit is rarely operated at a high capacity unless overall demand at the site requires it.

**Figure B-22: Scatter of Generation and Demand by Maximum Demand Day Quartiles, High Correlation Case One**



While the relationship between generation and demand is clear in Figure B-22, in Figure B-23 there is no evidence to suggest that the DG unit operates at a higher level to meet facility needs. This is in large part because the demand profile at the site is very flat on mean, with no significant hourly variation. Likewise, the generation profile is also flat, meeting a nearly constant three quarters of the overall site demand. One must refer back to Figure B-22, which shows that the daily maximum demand values are significantly distributed, to be sure both the generation and demand profiles are not at nearly constant levels on all days.

**Figure B-23: Mean Hourly Generation and Total Demand, High Correlation, Case One**



The second case of a site with a strong relationship between generation and demand is presented in Figure B-24 and Figure B-25. The correlation of 0.815 is the strongest of the three examples presented, with the data points in Figure B-24 clearly showing the increase in generation as demand rises. There are many more data points at or near zero generation compared to the first, showing that this unit has more of an on-and-off operation schedule. The hourly mean profiles shown in Figure B-25 add more support for the non-baseload classification of the generation profile. In stark contrast to Figure B-21, the contribution of generation to meeting total demand actually goes up during the hours when demand increases, meeting more than 50% of the site's needs during the peak afternoon hours.

**Figure B-24: Scatter of Generation and Demand by Maximum Demand Day Quartiles, High Correlation Case Two**

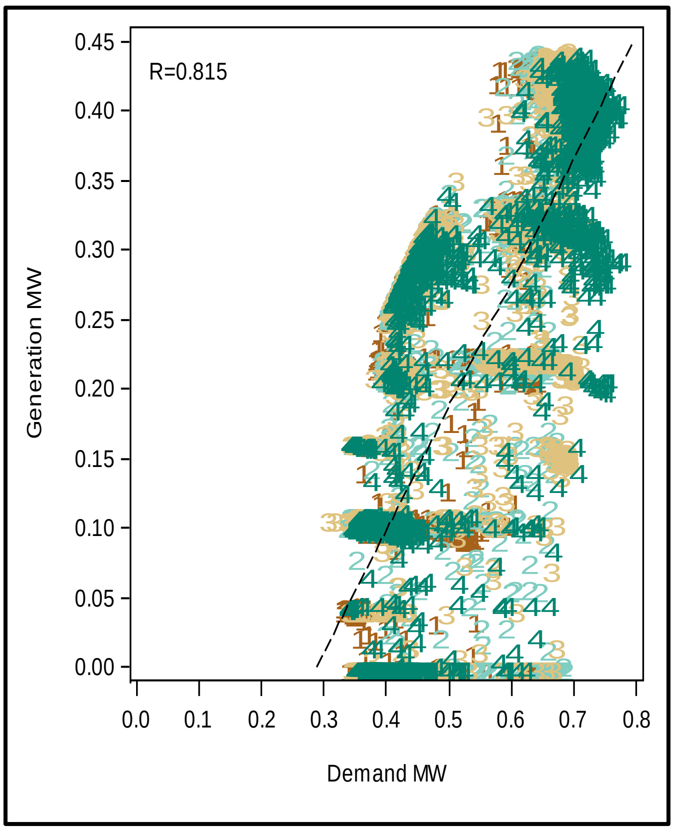
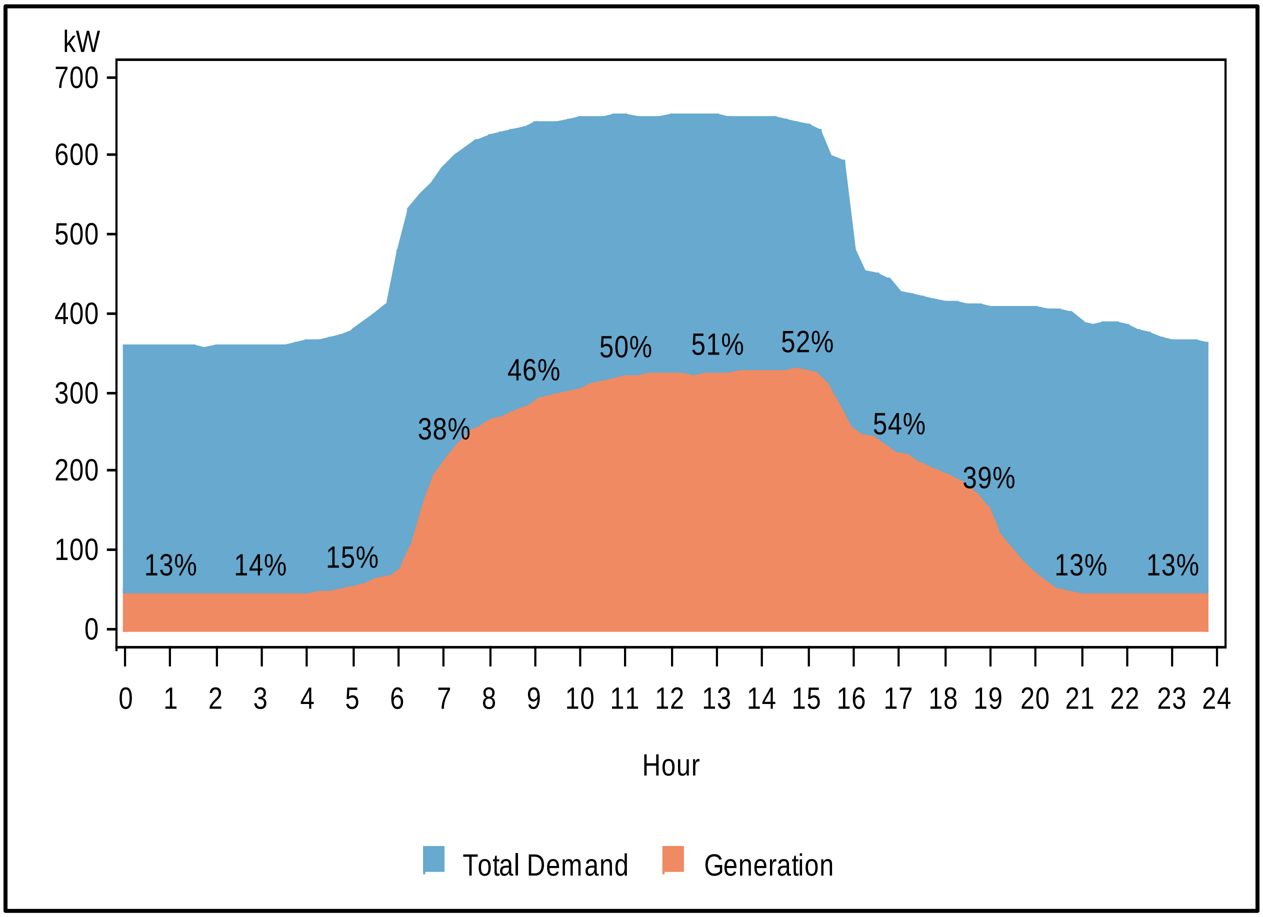


**Figure B-25: Mean Hourly Generation and Total Demand, High Correlation Case Two**



The examples presented above provide illustrations for individual sites. Table B-7 provides the counts of sites and mean correlations for classified load profile by the location, site type, and DG technology. The most interesting result is the overall correlations for the two types of classified generation profile. Those sites classified as baseload had a correlation between demand and generation of just 0.058 while the non-baseload sites – though there were only two of them – had a correlation of 0.553. Also worthy of note is that there were four process sites with baseload generation profiles with a correlation of 0.254, which suggests that there might have been some misclassifications.

**Table B-7: Mean Correlations of Generation and Site Demand**

| | | Baseload | | Non-Baseload | |
|---|---|---|---|---|---|
| **Summary Level** | **Value** | **Sites** | **R** | **Sites** | **R** |
| Location | Coastal | 6 | -0.009 | 2 | 0.553 |
| | Inland | 6 | 0.125 | . | . |
| Site Type | Occupancy | 8 | -0.040 | 2 | 0.553 |
| | Process | 4 | 0.254 | . | . |
| Technology | Fuel Cell | 1 | -0.074 | . | . |
| | IC Engine | 6 | 0.090 | 1 | 0.291 |
| | Microturbine | 5 | 0.047 | 1 | 0.815 |
| Overall | | 12 | 0.058 | 2 | 0.553 |

## B.5 Contribution of Generation to Site Demand

The availability of site demand data allow for an analysis of how much generation helps to meet site demand. While this topic was raised in the previous section for specific sites, for summaries covering all sites, Figure B-26, Figure B-27, Figure B-28, and Figure B-29 show generation as a percentage of demand by deciles of peak demand for the four summary categories used throughout this appendix (generation profile, technology, site type, and location, respectively).

The share of generation by the classified generation profile, as shown in Figure B-26, reveals a pattern where the baseload profiles meet an ever decreasing share of demand as demand increases. This result is intuitive, as the baseload generation remains at constant levels even as site demand increases. In contrast, the share associated with generation for non-baseload generation profiles actually goes up as site demand increase. The share of demand in the ninth and ten deciles is roughly same, most likely due to DG reaching its capacity.

**Figure B-26: Generation as Share of Demand by Demand Deciles and Generation Profile**

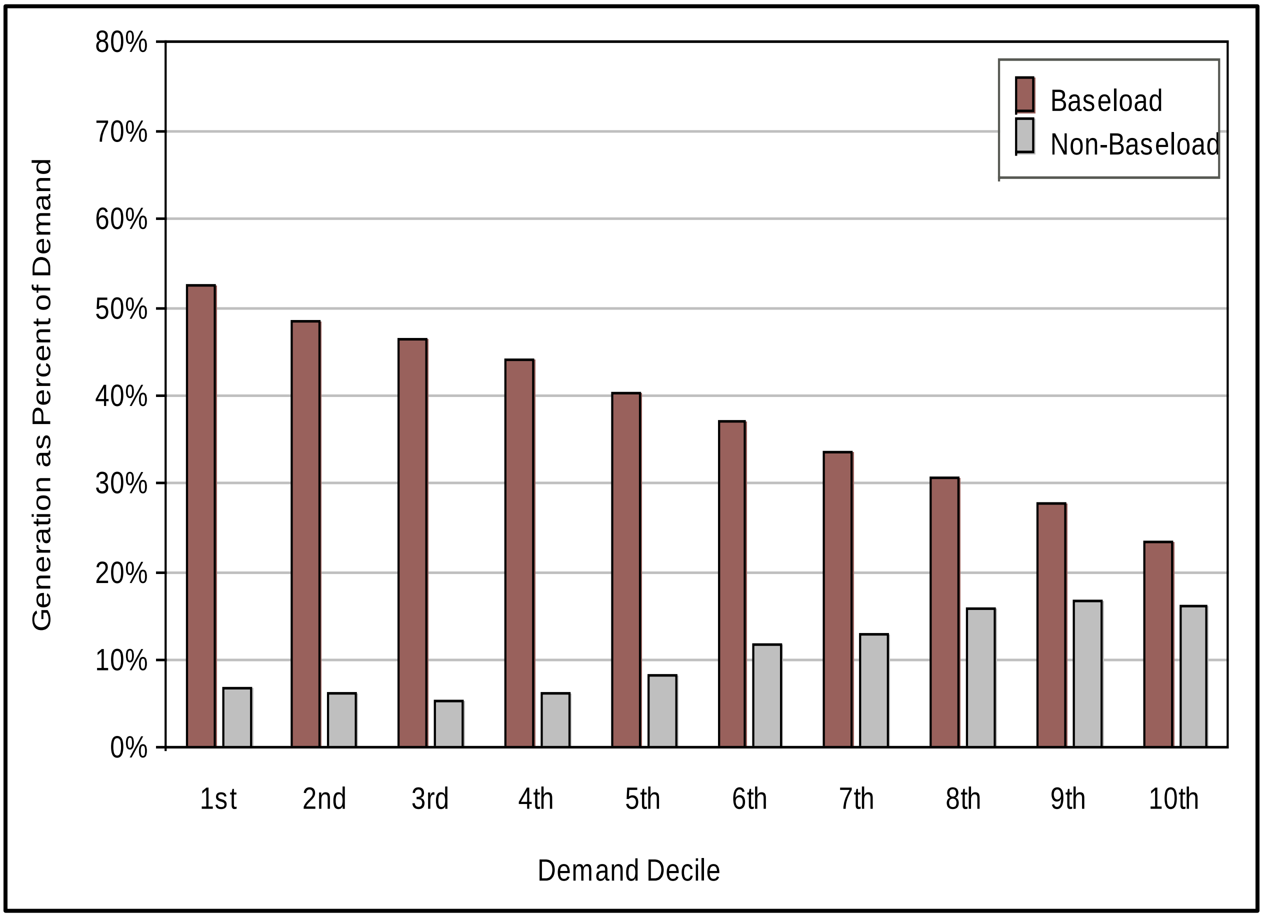


Figure B-27, Figure B-28, and Figure B-29, which show share of demand by DG technology, site type, and location, respectively, unfortunately do not reveal any particularly noteworthy patterns. This is because the baseload sites are dominant in every category, so the same general decline in generation share seen in Figure B-26 is repeated for all series.

**Figure B-27: Generation as Share of Demand by Demand Deciles and Technology Type**

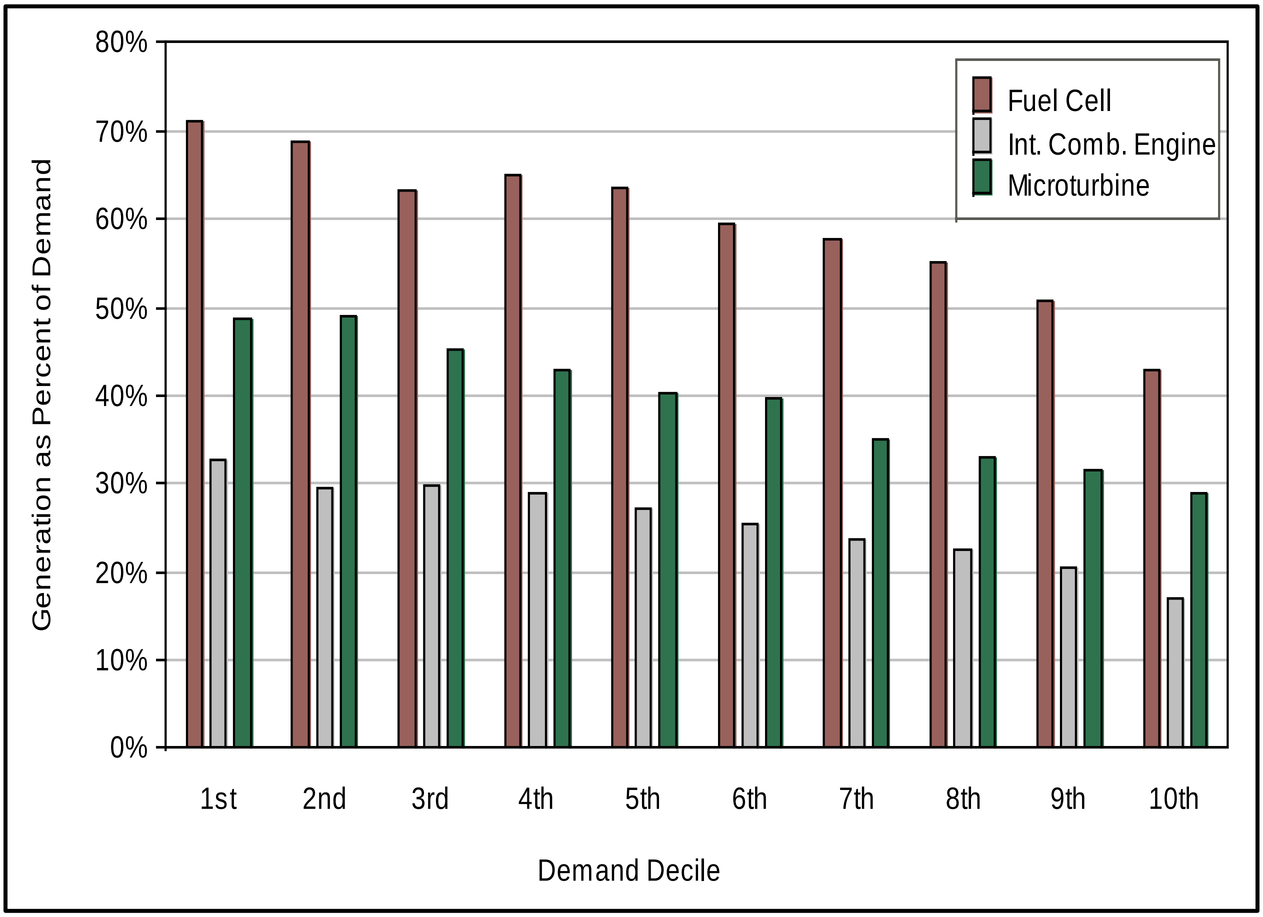


**Figure B-28: Generation as Share of Demand by Demand Deciles and Site Type**

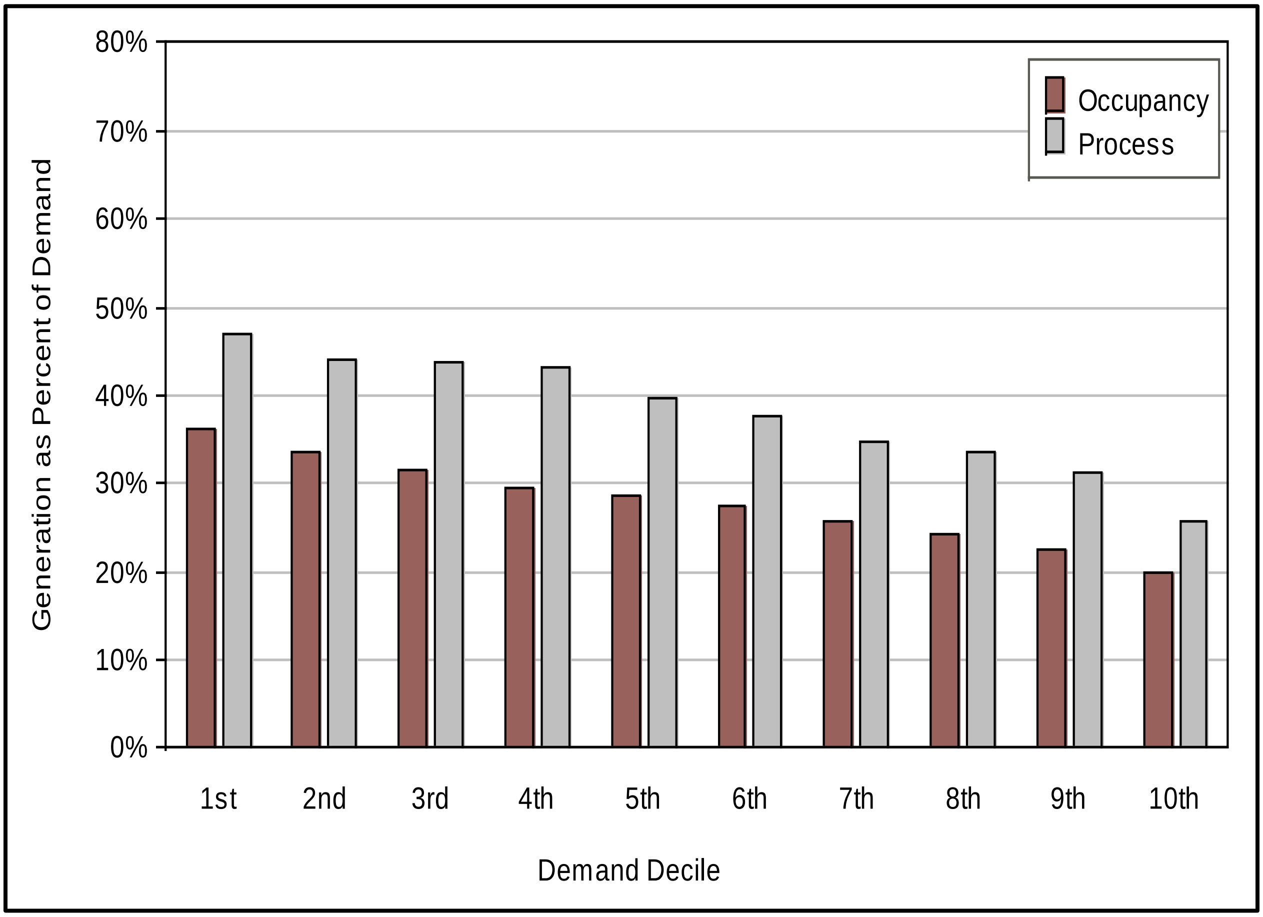


**Figure B-29: Generation as Share of Demand by Demand Deciles and Location**