Demand-side Management Market Potential Study

Volume 5: Distributed Generation Analysis

Final Report

EnerNOC Utility Solutions Consulting
500 Ygnacio Valley Road
Suite 450
Walnut Creek, CA 94596
925.482.2000
www.enernoc.com

Prepared for:
Ameren Missouri

Presented on:
December 20, 2013

This report was prepared by

EnerNOC Utility Solutions Consulting
500 Ygnacio Valley Blvd., Suite 450
Walnut Creek, CA 94596

I. Rohmund, Director
B. Kester, Project Manager
C. Arzbaecher
C. Carrera
D. Costenaro

CONTENTS

LIST OF FIGURES

LIST OF TABLES

CHAPTER | 1

INTRODUCTION

Ameren Missouri commissioned this Demand Side Management (DSM) Market Potential Study to assess the various categories of electrical energy efficiency (EE), demand response (DR), distributed generation (DG), and combined heat and power (CHP) potentials in the residential, commercial, and industrial sectors for the Ameren Missouri service area from 2016 to 2033. The study uses updated baseline estimates based on the latest information pertaining to federal, state, and local codes and standards for improving energy efficiency. It also quantifies and includes estimates of naturally occurring energy efficiency in the baseline projection.

Ameren Missouri will use the results of this study in its integrated resource planning process to analyze various levels of energy efficiency related savings and peak demand reductions attributable to both EE and DR initiatives at various levels of cost. This study also provides estimated levels of combined heat and power and distributed generation installations over the specified time horizon. This report is Volume 5, which addresses the distributed generation and combined heat and power analysis.

Furthermore, Ameren Missouri has adhered to both the Missouri Public Service Commission ("Commission") rules, 4 CSR 240-3.164 regarding potential study requirements for purposes of complying with the Missouri Energy Efficiency Investment Act (MEEIA) and 4 CSR 240-22 regarding potential study requirements for Ameren Missouri's next Integrated Resource Plan (IRP) to be filed in April 2014. Both rules contain new provisions that were not part of Ameren Missouri's previous DSM Potential Study published in 2010.

Ameren contracted with EnerNOC Utility Solutions Consulting (EnerNOC) to conduct this study and EnerNOC has performed the following tasks to meet Ameren's key objectives:

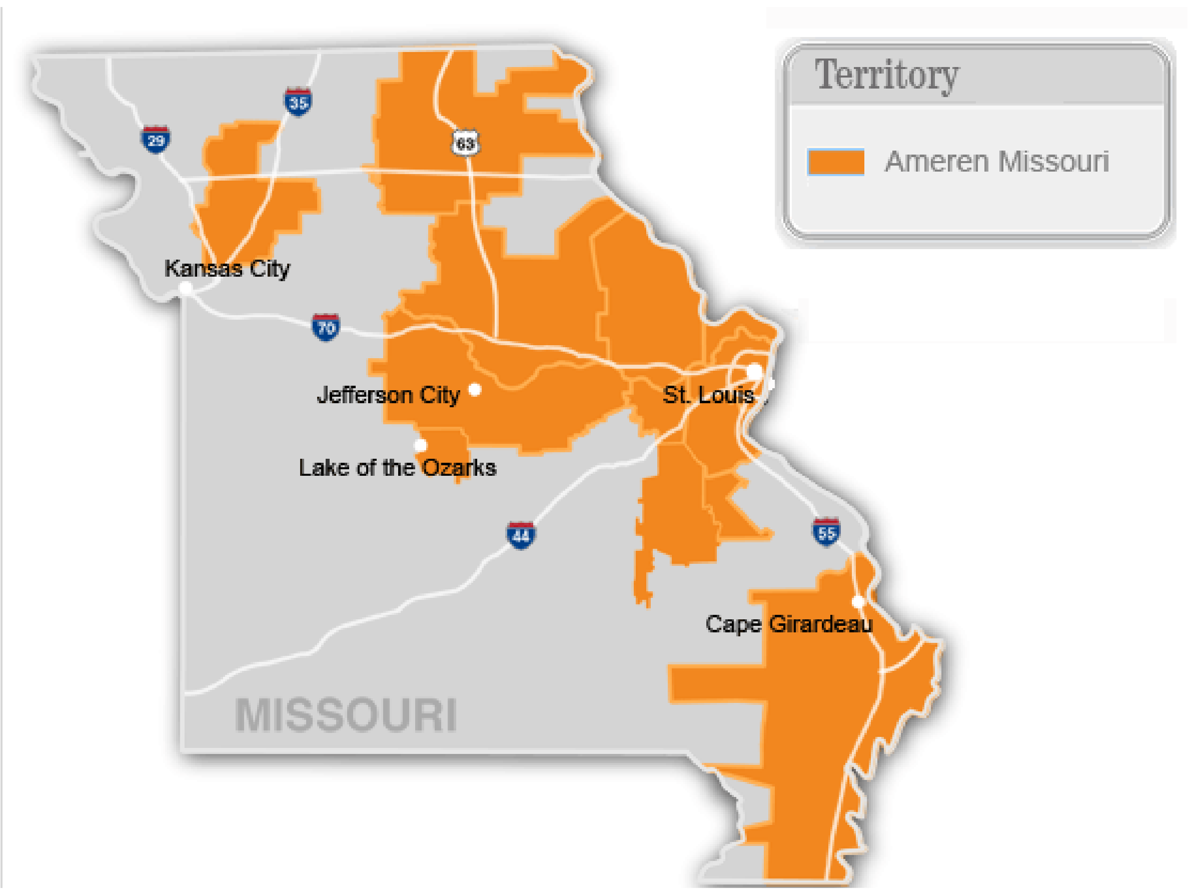
- Conducted primary market research to collect data for the Ameren Missouri service territory, including: electric end-use data, saturation data, and customer demographics and psychographics.
- Characterized how customers in the Ameren Missouri service territory make decisions related to their electric use and energy efficiency investment decisions. Translated that understanding in a clear and transparent manner to establish annual market acceptance rates for EE measures.
- Employed updated baselines that reflect both current and anticipated federal, state, and local energy efficiency legislation. Identified all known pending legislation that may also impact DSM potential.
- Developed Ameren Missouri-specific market acceptance rates for EE for the planning cycle of 2016 through 2033 that, when applied to economic potential, will yield estimates of maximum achievable and realistic achievable potential.
- Analyzed the potential for energy efficiency, demand response, and customer distributed generation/combined heat and power application over the 2016-2033 planning horizon.
- Worked with Ameren Missouri to develop sensitivity analyses for assessing uncertainty around DSM potential.
- Analyzed the impact of demand-side rates on DSM potential.
- Provided a series of webinars for Missouri stakeholders to review study assumptions and provide comments for consideration.

- Clearly communicated the DSM potential and uncertainty in an objective way that is useful for the Commission, Ameren senior management, Missouri stakeholders, Ameren DSM staff, Ameren EE Implementation team, and Ameren IRP staff – both operational and planning. This includes the following:
    - Documented compliance with IRP/MEEIA rule references, including specific references to rule requirements.
    - Provided measure-level information, in a way that is readily compatible with Ameren Missouri's modeling methodology in DSMore.
    - Generated energy efficiency potential supply curves, which clearly show the incremental cost (in dollars per kWh) of increasing DSM energy efficiency efforts (in kWh) over the 2016-2033 planning horizon.
    - Generated demand response potential supply curves, which clearly show the incremental cost (in dollars per kW) of increasing DSM demand response efforts (in kW) over the 2016-2033 planning horizon.
    - Generated distributed generation/combined heat and power potential supply curves, which clearly show the incremental cost (in dollars per kW) of increasing DG-CHP efforts (in kW) over the 2016-2033 planning horizon.

Background

Ameren Corporation is a large investor-owned utility serving large parts of Missouri and Illinois. Figure 1-1 presents Ameren Missouri's service territory.

Figure 1-1 Ameren Missouri Service Territory



Ameren Missouri DSM Overview

The Missouri Rules of the Department of Economic Development (4 CSR 240-22) require that electric utilities in Missouri prepare an integrated resource plan (IRP) that "[c]onsider[s] and analyze[s] demand-side efficiency and energy management measures on an equivalent basis with supply-side alternatives in the resource planning process." per Section 4 CSR 240-22.010(2)(A). Section 4 CSR 240-22.050 prescribes the elements of the demand-side analysis, including reporting requirements. A copy of the Missouri rules governing electric utility resource planning is available on the Missouri Secretary of State's website. Details of MEEIA are available on the Missouri Public Service Commission website.

Over the past several years, Ameren Missouri has been implementing EE programs and analyzing EE as a long-term resource option. From 2009 through September, 2011, Ameren Missouri implemented full-scale EE programs including five residential and four business programs.

Ameren Missouri spent approximately $70 million on energy efficiency programs between 2009 and 2011 and achieved approximately 550,000 MWH of verified energy savings. This level of expenditure resulted in deployment of approximately:

- 4 million CFLs
- 21,000 ENERGY STAR® appliances
- 12,000 upgraded Multi-Family Income Qualified (MFIQ) tenant units
- 9,000 decommissioned refrigerators and freezers
- 3,000 new residential central air conditioning systems
- 3,000 business energy efficiency projects

In 2012, Ameren Missouri scaled back its energy efficiency expenditures to $10 million due to uncertainty regarding regulatory framework issues for its next cycle of energy efficiency programs. Concurrently, in January 2012, Ameren Missouri filed its first 3-year EE implementation plan under the new Missouri rules implementing MEEIA.

Key Definitions

In this study, we estimate the potential for distributed generation impacts from utility demand side programs. This includes three types of customer-sited resources as follows:

- **Distributed generation:** DG systems are technologies that generate electricity and are located onsite at customer premises.
- **Combined heat and power:** CHP systems generate both electricity and thermal energy that are used onsite.
- **Peak-load shifting (PLS):** PLS technologies use energy storage methods that allow a facility to move some of its peak electric demand to off-peak times, for example, to take advantage of a time-of-use (TOU) rate that might price electricity at lower rates at night than in the day.

The impact estimates provided here represent demand-side *production* of energy, which is equivalent to energy and demand *reductions* from the perspective of the power grid and utility programs.

Three types of potential are examined here: technical potential, economic potential and achievable potential. Each level of potential is developed with reference to a baseline projection. The baseline projection, technical potential, and economic potential are defined as follows:

- **Baseline projection** is a reference end-use forecast developed specifically for this study. This estimates what would happen in the absence of any DSM programs, and includes naturally occurring energy efficiency and savings from equipment standards and building codes that were active and on the books for future enactment as of June 30, 2013. It is the metric against which savings are measured. The approach used to develop this projection is an end-use forecast approach and it is fundamentally different than the statistically-adjusted end-use approach used by Ameren to develop its official load forecasts. However, as much as possible, the forecast assumptions are the same and the resulting forecasts are close.

- **Technical potential** is defined as the theoretical upper limit of DSM potential. It assumes that customers adopt all feasible and applicable measures regardless of their cost. For EE, technical potential is constrained in that the efficiency of a particular end use ranges between 0% and 100%. In the case of DG, however, one can imagine a hypothetical case in which customers line their back yards with multiple generator units and sell to the grid at levels higher than 100% of their consumption. For purposes of this analysis, DG technical potential is constrained based on the assumption that customers will only install typical systems, in applicable locations, that meet their native load requirements. These measures are phased in throughout the timeframe of the study.
- **Economic potential** represents the adoption of all ***cost-effective*** measures. In this analysis, cost-effectiveness is measured by the total resource cost (TRC) test, which compares lifetime energy and capacity benefits to the incremental cost of the measure. If the benefits outweigh the costs (that is, if the TRC ratio is greater than 1.0), a given measure is considered in the economic potential. Customers are then assumed to purchase the most cost-effective option applicable to them at any decision juncture.

Achievable potential is a subset of economic potential in which customers choose to adopt measures that are cost-effective and offered through utility DSM programs. Achievable potential embodies a set of assumptions about the decisions consumers make regarding the equipment they purchase, the maintenance activities they undertake, and the energy needs at their location. Because estimating achievable potential involves the inherent uncertainty of predicting human behaviors and responses to market conditions, we developed two estimates of achievable potential as described below.

- **Maximum achievable potential (MAP)** takes into account expected program participation, based on customer preferences resulting from ideal implementation conditions. MAP establishes a maximum target for the impacts that a utility can hope to achieve through its DSM programs and involves incentives that represent a substantial portion of the incremental cost combined with high administrative and marketing costs. It is commonly-accepted in the industry that MAP is considered the hypothetical upper-boundary of achievable savings potential simply because it presumes conditions that are ideal and not typically observed in real-world experience.
- **Realistic achievable potential (RAP)** represents what is considered to be realistic estimates of impact potential based on realistic parameters associated with DSM program implementation (i.e., limited budgets, customer acceptance barriers, etc.).

Report Organization

This report is presented in six volumes as outlined below. This document is **Volume 5: Distributed Generation Analysis**.

- Volume 1, Executive Summary
- Volume 2, Market Research
- Volume 3, Energy Efficiency Analysis
- Volume 4, Demand Response Analysis
- Volume 5, Distributed Generation Analysis
- Volume 6, Demand-side Rates Analysis

Abbreviations and Acronyms

Throughout the report we use several abbreviations and acronyms. Table 1-1 shows the abbreviation or acronym, along with an explanation.

Table 1-1 Explanation of Abbreviations and Acronyms

Acronym	Explanation
B/C Ratio	Benefit to Cost Ratio
C&I	Commercial and Industrial
CCCT	Combined Cycle Combustion Turbine
CT	Combustion Turbine
CHP	Combined Heat and Power
DG	Distributed Generation
DR	Demand Response
DSM	Demand side management
EE	Energy Efficiency
IRP	Integrated Resource Plan
MAP	Maximum Achievable Potential
MEEIA	Missouri Energy Efficiency Investment Act
MFIQ	Multi-Family Income Qualified
MISO	Midwest Independent System Operator
MW	Megawatt
NPV	Net Present Value
PLS	Peak Load Shifting
Solar PV	Solar Photovoltaic
RAP	Realistic Achievable Potential
TOU	Time-of-Use
TRC	Total Resource Cost

ANALYSIS APPROACH AND DATA DEVELOPMENT

This section describes the analysis approach taken for the study and the data sources used to develop the potential estimates for DG, CHP and PLS technologies.

Approach for DG, CHP, and PLS Analysis

We used the following steps to estimate potential:

1. Identified relevant DG, CHP, or PLS technologies for each sector
2. Characterized the typical installation, which included determining the sizing, costs, lifetimes, and applicability for a typical installation in each segment
3. Analyzed the technical, economic, and achievable potential based on the above.

The analysis for DG and CHP technologies was combined, as CHP applications are merely extensions of a generation application that also harness the waste heat for a specific purpose. PLS technologies are distinct in that they shift load from one time period to another, rather than impacting the overall amount of load. Therefore, PLS technologies were analyzed separately and are presented in a separate chapter.

Before performing the service-territory analysis, we conducted two in-depth cases studies of DG-CHP opportunities that were being considered by Ameren customers: one at a major corn milling facility and another at a major manufacturing facility. These case studies, presented in Chapter 3, provide perspective on regional pricing levels, issues related to grid and utility integration, and risk and uncertainty.

Data Development

A variety of data sources were used to develop the analysis assumptions regarding energy impacts, cost, lifetime, and applicability.

DG-CHP Analysis

1. *Cost-Effectiveness of Distributed Generation Technologies*, Appendix A, Final Report, CPUC Self-Generation Incentive Program, prepared by Itron, 2011
2. *Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment,* California Energy Commission, prepared by ICF International, 2012
3. Budgetary Quotes (5) from manufacturer Solar Turbines
4. *Distributed Generation Renewable Energy Estimate Costs*, NREL, July 2012
5. *Cost and Performance Data for Power Generation Technologies*, NREL, prepared by Black & Veatch, 2012
6. *Residential, Commercial, and Utility-scale PV System Prices in the United States: Current Drivers and Cost-Reduction Opportunities*, NREL, 2012
7. *Catalog of CHP Technologies*, EPA, 2008
8. *Sunshot Vision Study*, NREL, 2012; http://www1.eere.energy.gov/solar/pdfs/47927.pdf
9. *MicroCHP blog*, http://www.microchap.info/Stirling_engine.htm
10. *Tracking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012*, LBNL Report, 2013

11. Tax Credit information: http://energy.gov/savings/business-energy-investment-tax-credit-itc

Peak Load Shifting Analysis

1. *Statewide Joint IOU Study of Permanent Load Shifting*, E3 and StrateGen, 2011
2. *Electricity Energy Storage Technology Options*, White Paper, EPRI, December 2010
3. *International Energy Storage Database*, DOE
4. KEMA/Sandia ES-Select Tool
5. Technology Brief E17, Thermal Energy Storage, IEA-ETSAP and IRENA, 2013

IN-DEPTH CASE STUDIES

This section describes in-depth case studies of DG-CHP applications for two Ameren customers: a major corn milling facility and a major manufacturing facility. The customer names and specific details of the case studies are proprietary, but relevant findings and lessons learned are documented here.

We began our analysis by gathering basic facility operational data from the customers through the Ameren Key Account Executives. This data included annual operating hours, electricity use and billing demand for the last 24 months, and plant capacity sizing, equipment, and interface requirements for DG-CHP technology. We also conducted a site visit at one of the customer facilities to gather detailed operational data, typical maintenance schedules, heat/steam requirements for their operations, and other key information.

Using the data described above, we sized the most optimal DG-CHP system for each customer. Both systems were very large combustion turbine systems — more than 3 MW with heat recovery for process heating use — and as such were ideal pilot cases to gauge overall fit and economics for general applications in Ameren Missouri's service territory. The plants in these cases would have large economies of scale, significant up-time (90%+ hours in the year), and onsite heat requirements that would use all of the available waste heat.

To ensure that we used realistic cost inputs, our team requested budget quotations for five differently sized combustion turbines with heat recovery equipment from nationwide manufacturer Solar Turbines. These price quotations compared reasonably with other national and regional data sources, as discussed in the data development chapter above.

Specifics regarding installed costs and fuel costs are proprietary. Major, non-proprietary assumptions for the case study analyses were as follows:

- Natural gas fueled combustion turbine generator with 3+ MW of electricity generating capacity; producing waste heat in the form of steam for process heating
- Waste heat valuation based on displacing boiler fuel use
- Annual O&M costs include turbine overhaul cost at half-life
- 20 year system life
- $10,000 grid interconnection study cost
- Real discount rate of 3.95%
- Uptime of 90%+ hours per year
- Avoided cost benefits for energy and capacity as provided by Ameren Missouri

The results of the technical and economic analysis are shown in Table 3-1. Although the TRC ratios are above 1.0, indicating that the projects are cost-effective, they are sensitive to many factors. During a drought-year, production and heating requirements at the milling facility may fall, reducing the value of waste heat. In a sensitivity analysis to model a prolonged drought scenario, the TRC ratio dropped to 1.01. An additional factor to consider is the customer's Ameren Missouri rate structure, which contains a standby charge (Rider E) for Ameren to maintain the necessary capacity if the customer would choose to revert to grid power in the event of an emergency shut-down of their DG-CHP system. For sizeable systems, the details of this cost result from a complex interconnection study, scenario analysis, and negotiation — and can have a significant impact on the overall project economics.

Table 3-1 Total Resource Cost (TRC) Test Results for DG-CHP Case Studies

Case Study	TRC Ratio	NPV Net Benefits	NPV Benefits	NPV Costs
Major Corn Milling Facility	1.17	$8,577,664	$58,910,946	$50,333,283
Major Manufacturing Facility	1.04	$1,378,710	$32,167,172	$30,788,462

In conclusion, these two near-ideal case studies show that the economics are positive but marginally so. When extrapolating the lessons learned to the broader service territory, one can say that there is definitely opportunity for DG-CHP application, but that the economics are not necessarily a sure win and each instance should be examined and considered carefully.

DG-CHP ANALYSIS

This section describes the DG and CHPS potential analysis and then provides the resulting potential impact estimates.

Identify Relevant DG-CHP Technologies

The first step toward estimating DG-CHP was to identify applicable technology options. Based on a thorough review of available and applicable technologies, as well as input from stakeholders, we arrived at the following list:

- Solar photovoltaic (PV) systems
- Small wind
- Reciprocating engine
- Reciprocating engine with heat recovery
- Micro-turbine
- Micro-turbine with heat recovery
- Combustion turbine (CT)
- Combustion turbine with heat recovery
- Boiler with back-pressure steam turbine
- Fuel cell
- Fuel cell with heat recovery
- Combined cycle combustion turbine (CCCT)
- Stirling engine
- Organic rankine cycle

The next step was to consider the size and applicability of a typical installation in each customer segment. This involved answering the following questions:

- Are the electrical loads, and thermal loads if applicable, significant and relatively constant? Do the demands match the output of the DG-CHP technology?
- Is there a readily available feedstock as a byproduct of onsite or nearby operations, such as wood chips at a lumber mill or digester gas from an industrial process?
- For solar PV, how much roof space or other suitable installation space is available?
- For small wind, what is the surrounding topography and access to wind resources?
- For CHP, what are the typical thermal loads, i.e., hot water, low-pressure steam, high-pressure steam, cooling via absorption chillers, etc.? What CHP technology can generate waste heat of sufficient quality to meet these thermal loads?

If the technology was feasible and applicable, a system size was matched to the typical customers as shown by segment in Table 4-1. If a cell in the table does not contain a value, the technology is assumed to be inapplicable in that segment.

Additional comments on customer applicability are as follows:

- **Small Wind —** Missouri has limited wind resources except for the Northwest corridor of the state, which is outside of Ameren Missouri's service territory. Therefore, customer applicability is low.
- **Combustion Turbine and Combustion Turbine with Heat Recovery** — For commercial applications, only the larger schools, universities, and warehouses will have a large enough electric and thermal load. For industrial applications, not all plants have a large enough peak load to warrant installation.
- **Boiler with back-pressure steam turbine** — These systems are primarily found in paper mills, chemical plants, primary metals, and some food processing industries, as well as universities. In industrial applications, waste fuels and biomass, such as hog fuel, black liquor, wood chips, and refinery off-gases/oils, are typically used as fuel. The analysis assumes the site already has a boiler and the steam turbine is retrofitted to the pre-existing boiler. Where applicable, most of these opportunities have already been harvested or passed over for more modern, high temperature and top-cycling CHP options; leaving applicability relatively low.
- **Fuel Cell with Heat Recovery** – The combination of fuel cells with heat recovery has not been field-tested in the U.S. yet, and therefore applicability is low in the near term.
- **Combined Cycle Combustion Turbine** – The typical CCCT size of 50 MW is approaching utility scale and is not applicable for any customers in the Ameren Missouri service territory. For this reason, we screened out subsequent analysis of this technology.
- **Stirling Engine** - This technology has not been field-tested in the U.S. yet, and therefore applicability is low in the near-term.
- **Organic Rankine Cycle** – No fuel is required. Instead, this technology needs waste heat to operate, which may come from engines, turbines, or industrial processes.

Characterize Typical DG-CHP Installation

The next step was to analyze a typical installation in each customer segment. This involved asking the following questions:

- What are the installation costs, fuel costs, and annual O&M costs?
- What tax credits, state or regional rebates, or other economic incentives are available?
- What are the lifetime and typical annual operating hours?

The data to support this characterization is summarized in Table 4-2. The data source titles have been abbreviated here to save space, but the full source titles appear in the Data Development section of Chapter 2.

Table 4-1 DG-CHP Modeled System Sizes (kW) by Segment

Sector	Segment	Solar PV	Small Wind	Recip Engine	Recip Engine w/ Heat Recovery	Micro-turbine	Micro-turbine w/ Heat Recovery	Combustion Turbine (CT)	CT w/ Heat Recovery	Boiler w back-press steam turbine	Fuel Cell	Fuel Cell w/ Heat Recovery	Combined Cycle CT	Stirling Engine	Organic Rankine Cycle
Residential	Single Family	6	3	-	-	-	-	-	-	-	-	5	-	1	-
Residential	Multi Family	6	3	-	-	-	-	-	-	-	-	5	-	1	-
Commercial	Office	20	3	500	500	200	200	-	-	-	200	200	-	-	-
Commercial	Restaurant	6	3	-	-	-	-	-	-	-	-	-	-	-	-
Commercial	Retail	20	3	500	500	200	200	-	-	-	200	200	-	-	-
Commercial	Grocery	20	3	500	500	200	200	-	-	-	200	200	-	-	-
Commercial	College	20	3	500	500	500	500	2,000	2,000	3,000	200	200	-	-	-
Commercial	School	20	3	500	500	500	500	-	-	-	-	-	-	-	-
Commercial	Health	20	3	1,500	1,500	500	500	2,000	2,000	3,000	200	200	-	-	-
Commercial	Lodging	20	3	500	500	200	200	-	-	-	200	200	-	-	-
Commercial	Warehouse	20	3	500	500	200	200	2,000	2,000	-	-	-	-	-	-
Commercial	Miscellaneous	20	3	500	500	200	200	2,000	2,000	-	200	200	-	-	-
Industrial	Industrial	100	3	1,500	1,500	500	500	5,000	5,000	3,000	1,000	1,000	50,000	-	500

Table 4-2 DG-CHP Technology and Cost Data

Technology	System Size (kW)	Lifetime	$/kW installed cost (2011)	Non-fuel $/kWh annual O&M (2011)	Load factor (% available)	Nat Gas Fuel Use, BTU/kWh	Nat Gas Fuel Avoided, BTU/kWh	Federal tax credit	Inst. Cost Decline from Yr 1 to YrFinal	Peak Coinc. Factor	Useful Thermal Output, BTU/kWh	Effic.of Displaced Boiler	Data Source
Solar PV	6	20	$3,953	$0.002	15.0%	-	-	10.0%	78.7%	47.0%	-		4,5,6,8,10
Solar PV	20	20	$3,867	$0.001	15.0%	-	-	10.0%	78.7%	47.0%	-		4,6,7,10
Solar PV	100	20	$3,688	$0.001	15.0%	-	-	10.0%	78.7%	47.0%	-		4,5,6,7,10
Solar PV	1,000	20	$3,570	$0.001	15.0%	-	-	10.0%	78.7%	47.0%	-		4,5,7,10
Small Wind	3	20	$8,215	$0.020	15.0%	-	-	0.0%	10.0%	20.0%	-		4
Small Wind	30	20	$6,038	$0.020	20.0%	-	-	0.0%	10.0%	20.0%	-		4
Small Wind	300	20	$3,600	$0.020	25.0%	-	-	0.0%	10.0%	20.0%	-		1
Recip Engine	500	15	$1,950	$0.012	80.0%	9,755	-	0.0%	0.0%	80.0%	-		1,2
Recip Engine w/ Heat Recovery	500	15	$2,326	$0.012	80.0%	9,755	5,291	0.0%	0.0%	80.0%	4,233	80.0%	1,2
Recip Engine	1,500	15	$1,650	$0.007	80.0%	9,738	-	0.0%	0.0%	80.0%	-		1,2
Recip Engine w/ Heat Recovery	1,500	15	$1,980	$0.007	80.0%	9,738	5,298	0.0%	0.0%	80.0%	4,238	80.0%	1,2
Micro- turbine	200	15	$3,068	$0.020	80.0%	12,247	-	0.0%	0.0%	80.0%	-		1,2
Micro- turbine w/ Heat Recov.	200	15	$3,068	$0.020	80.0%	12,247	5,331	0.0%	0.0%	80.0%	4,265	80.0%	1,2
Micro- turbine	500	15	$3,068	$0.020	80.0%	12,247	-	0.0%	0.0%	80.0%	-		1,2
Micro- turbine w/ Heat Recov.	500	15	$3,068	$0.020	80.0%	12,247	5,331	0.0%	0.0%	80.0%	4,265	80.0%	1,2
Combustion Turbine (CT)	2,000	20	$3,000	$0.010	90.0%	14,085	-	0.0%	0.0%	80.0%	-		1,2,3
CT w/ Heat Recovery	2,000	20	$2,969	$0.010	90.0%	14,085	7,434	0.0%	0.0%	80.0%	5,947	80.0%	1,2,3
Combustion Turbine (CT)	5,000	20	$1,500	$0.010	90.0%	13,754	-	0.0%	0.0%	90.0%	-		1,2,3
CT w/ Heat Recovery	5,000	20	$1,485	$0.010	90.0%	13,754	7,206	0.0%	0.0%	90.0%	5,765	80.0%	1,2,3
Boiler w back-press steam turb.	3,000	50	$500	$0.005	80.0%	-		0.0%	0.0%	80.0%			2
Fuel Cell w/ Heat Recovery	5	12	$11,976	$0.022	90.0%	8,600	5,000	0.0%	10.0%	80.0%	4,000	80.0%	1,9
Fuel Cell	200	15	$5,048	$0.030	90.0%	8,022	-	0.0%	10.0%	80.0%	-		1, 2
Fuel Cell w/ Heat Recovery	200	15	$5,196	$0.030	90.0%	8,022	2,685	0.0%	10.0%	80.0%	2,148	80.0%	1,2
Fuel Cell	1,000	15	$5,048	$0.030	90.0%	8,022	-	0.0%	10.0%	90.0%	-		1, 2
Fuel Cell w/ Heat Recovery	1,000	15	$5,196	$0.030	90.0%	8,022	2,655	0.0%	10.0%	90.0%	2,124	80.0%	1,2
Stirling Engine	1	15	$18,000	$0.010	90.0%	12,186	7,614	0.0%	0.0%	80.0%	6,091	80.0%	8,10,11,12,13
Organic Rankine Cycle	500	15	$5,700	$0.007	80.0%	-	-	0.0%	0.0%	80.0%	-		1,10

Key to data sources:

1. *Cost-Effectiveness of Distributed Generation Technologies*, CPUC Self-Generation Incentive Program 2011	7. *Catalog of CHP Technologies*, EPA, 2008
2. *Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment*, CA Energy Commission/ICF, 2012	8. *Sunshot Vision Study*, NREL, 2012; http://www1.eere.energy.gov/solar/pdfs/47927.pdf
3. Budgetary Quotes (5) from manufacturer Solar Turbines	9. *MicroCHP blog*, http://www.microchap.info/Stirling_engine.htm
4. *Distributed Generation Renewable Energy Estimate Costs*, NREL, July 2012	10. *Tracking the Sun VI:* LBNL Report, 2013
5. *Cost and Performance Data for Power Generation Technologies*, NREL, prepared by Black & Veatch, 2012	11. *Tax Credit information: http://energy.gov/savings/business-energy-investment-tax-credit-itc*
6.*Residential, Commercial, and Utility-scale PV System Prices in the United States: NREL, 2012*	

Additional Technology Cost Considerations

Federal tax credits are scheduled to undergo funding and level changes at the end of 2016. Because the study period is 2016-2033, only the first year of the study is affected. Therefore Table 4-2 reflects the tax credits for systems placed in service after December 31, 2016. For the first year of the study, we altered the analysis to account for federal tax credits for systems placed in service before December 31, 2016:

- Solar: 30%
- Small wind: 30%
- Fuel cells: 30%
- Microturbines, CHP: 10%

We also considered the deferred tax benefits of applicable technologies for non-residential customers. "Under the federal Modified Accelerated Cost-Recovery System (MACRS), businesses may recover investments in certain property through depreciation deductions...Such property currently includes: a variety of solar-electric and solar-thermal technologies, fuel cells and microturbines, geothermal electric, direct-use geothermal and geothermal heat pumps, small wind (100 kW or less), and combined heat and power (CHP)."[1] The net effects of being able to alter the tax treatment in this way resulted in deferred income tax benefits worth 1% of the installed cost.

Other cost considerations by technology are delineated below.

- **Solar PV –** We included cost of inverter replacement and labor at half life, all applicable rebates (federal tax credit, Missouri state solar rebate, and Missouri SREC payment), and the increased cost of property taxes and insurance premiums. Peak coincidence of 50% multiplied by 94% AC/DC inverter efficiency factor. Further, we applied a cost declination factor for Solar PV of 6.5% per year, based on the report *Tracking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012*, LBNL Report, July 2013. The report states that, "Over the entirety of the historical period depicted in Figure 7 (1998-2012), installed prices have declined by about $0.5/W (6-7%) per year, on average, depending on the system size."
- **Reciprocating Engine –** Due to forthcoming environmental regulations from the EPA (RICE/NESHAP), we have included a cost for Selective Catalytic Reduction (SCR) equipment to all new reciprocating engine installations so they can maintain environmental compliance. This impacts the cost-effectiveness such that the technology is only economic from a TRC perspective in concert with a heat recovery application.
- **Reciprocating Engine with Heat Recovery, Micro-turbine with Heat Recovery, and Combustion Turbine with Heat Recovery, Fuel Cell with Heat Recovery —** Heat recovery can be used for multiple purposes, one of them being an absorption chiller, which will cause costs to rise between 5% and 20% relative to the assumptions currently in the model.

DG and CHP Potential Calculation and Results

Using data from our market research, from Ameren's Renewables group, and other national sources, we identified the baseline existing saturations of the DG-CHP technologies and removed them from the applicable potential opportunities. For the remaining opportunities, systems installed in each segment create energy and peak demand impacts that are subtracted from the segment-level baseline forecasts that were developed separately as part of the energy efficiency analysis (see Volume 3).

---

[1] Database of State Incentives for Renewables and Efficiency: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US06F

For those customer segments where each technology is applicable, the technical potential is phased into the market using an s-shaped, diffusion curve. This assumes that customers adopt all feasible and applicable measures regardless of their cost. Technical potential for distributed generation is different than when calculated for energy efficiency. For EE, technical potential is constrained in that the efficiency of a particular end use ranges between 0% and 100%. In the case of DG, however, it is theoretically possible for customers to generate at levels higher than 100% of their consumption and to sell the excess to the grid. For purposes of this analysis, DG-CHP technical potential is constrained based on the assumption that customers will only install systems that meet their native load requirements.

The costs and benefits of each application are then weighed using the total resource cost test. For each option that is cost-effective according to this definition, i.e. having a TRC benefit-to-cost ratio higher than 1.0, the technical potential is included in the analysis results as economic potential.

Once the economic screen is complete, market adoption factors are applied to estimate maximum achievable potential and realistic achievable potential. To reflect the relatively slow market adoption of DG-CHP measures, we have aligned with the market research and the energy efficiency analysis, using the most conservative family of curves developed for the EE analysis. In general, unfavorable economics screen out a large swath of technical potential, and even for those technology applications that are cost-effective, market adoption is low, given the relative complexity of purchasing, owning, operating, and maintaining the units.

Note that this analysis is only concerned with participation and impacts from the perspective of utility DSM programs. Due to the emerging nature of this market and the heavily subsidized and complex market interactions, we are not making any assumptions about free-ridership, the individual effects of multiple subsidies, or the “green” social premium that many of these technologies carry. Therefore energy and peak impacts reported here are both gross and net with a NTG ratio of 1.0. Additionally, we note that the participant cost perspective is typically more attractive and a lower threshold than the utility cost perspective and the total resource cost perspective, due to the fact that retail rate savings are higher than avoided cost savings. All this being said, some customer adoption of these technologies is expected to occur regardless of program activity.

The realistic achievable potential savings in 2030 are 488 cumulative GWh or 1.4% of the baseline projection. The corresponding maximum achievable potential savings in 2030 are 672 GWh, or 2.0% of the baseline projection. The following tables and figures summarize the results of the DG-CHP savings potential analysis. Solar PV accounts for a significant portion of the 2030 potential.

Table 4-3 DG-CHP Energy Impact Results

	2016	2017	2018	2025	2030
Baseline Forecast (GWh)	**30,249**	**30,449**	**30,694**	**32,228**	**33,721**
Cumulative Energy Savings (GWh)					
Realistic Achievable	6	7	9	43	488
Maximum Achievable	8	10	13	60	672
Economic Potential	57	72	90	389	4,159
Technical Potential	720	898	1,119	4,729	10,946
Energy Savings (% of Baseline)					
Realistic Achievable	0.0%	0.0%	0.0%	0.1%	1.4%
Maximum Achievable	0.0%	0.0%	0.0%	0.2%	2.0%
Economic Potential	0.2%	0.2%	0.3%	1.2%	12.3%
Technical Potential	2.4%	2.9%	3.6%	14.7%	32.5%

Figure 4-1 DG-CHP Energy Impact Results (GWh)

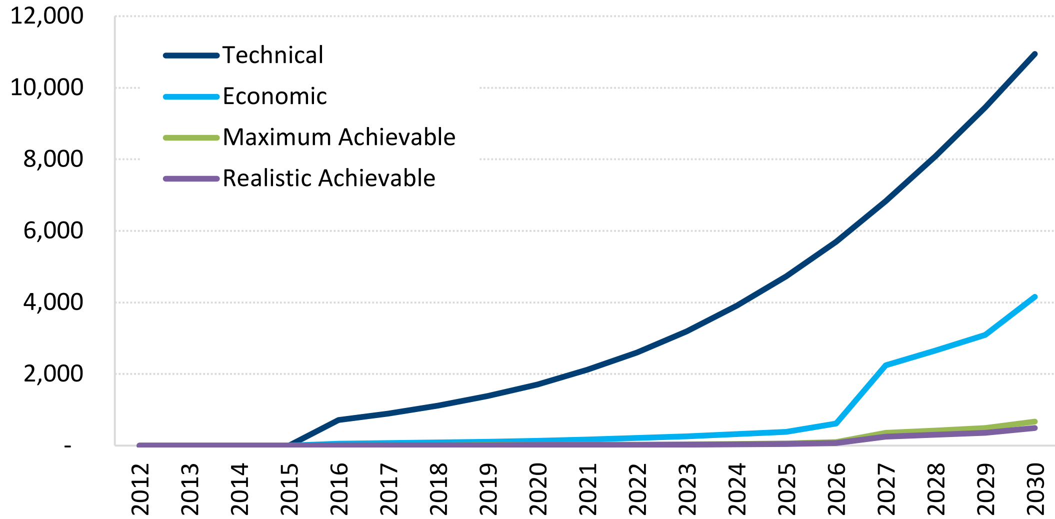


Table 4-4 and Figure 4-2 present the peak demand impacts. The realistic achievable potential savings in 2030 are 132 cumulative MW or 1.7% of the baseline projection. The corresponding maximum achievable potential savings in 2030 are 182 MW, or 2.3% of the baseline projection.

Table 4-4 DG-CHP Peak Demand Impact Results

	2016	2017	2018	2025	2030
Baseline Forecast (MW)	**6,987**	**7,035**	**7,091**	**7,447**	**7,792**
Peak Savings (MW)					
Realistic Achievable	1	1	1	5	132
Maximum Achievable	1	1	2	7	182
Economic Potential	7	8	10	44	1,127
Technical Potential	124	154	192	803	1,851
Peak Savings (% of Baseline)					
Realistic Achievable	0.0%	0.0%	0.0%	0.1%	1.7%
Maximum Achievable	0.0%	0.0%	0.0%	0.1%	2.3%
Economic Potential	0.1%	0.1%	0.1%	0.6%	14.5%
Technical Potential	1.8%	2.2%	2.7%	10.8%	23.8%

Figure 4-2 DG-CHP Peak Demand Impact Results (MW)

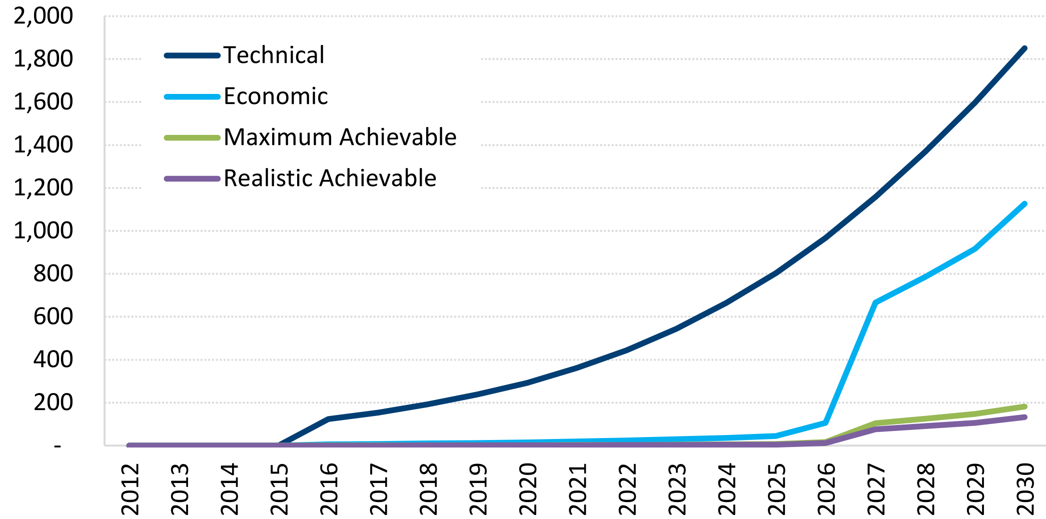


Table 4-5 shows the economic savings potential by segment for selected years. Figure 4-3 presents a graphical summary for the years 2016-2030. The largest potential impacts in 2030 come from Single Family, Industrial, Health, Multi Family, and then Office.

Table 4-5 DG-CHP Energy Economic Potential by Segment (GWh)

Segment	2016	2017	2018	2025	2030
Single Family	-	-	-	-	2,031
Multi Family	-	-	-	-	352
Office	-	-	-	-	282
Restaurant	-	-	-	-	14
Retail	-	-	-	-	159
Grocery	-	-	-	-	30
College	2	2	2	10	38
School	-	-	-	-	93
Health	24	30	38	167	420
Lodging	-	-	-	-	16
Warehouse	-	-	-	-	45
Miscellaneous	-	-	-	-	145
Other industrial	31	39	49	212	534
Total	**57**	**72**	**90**	**389**	**4,159**

Figure 4-3 DG-CHP Energy Economic Potential by Segment

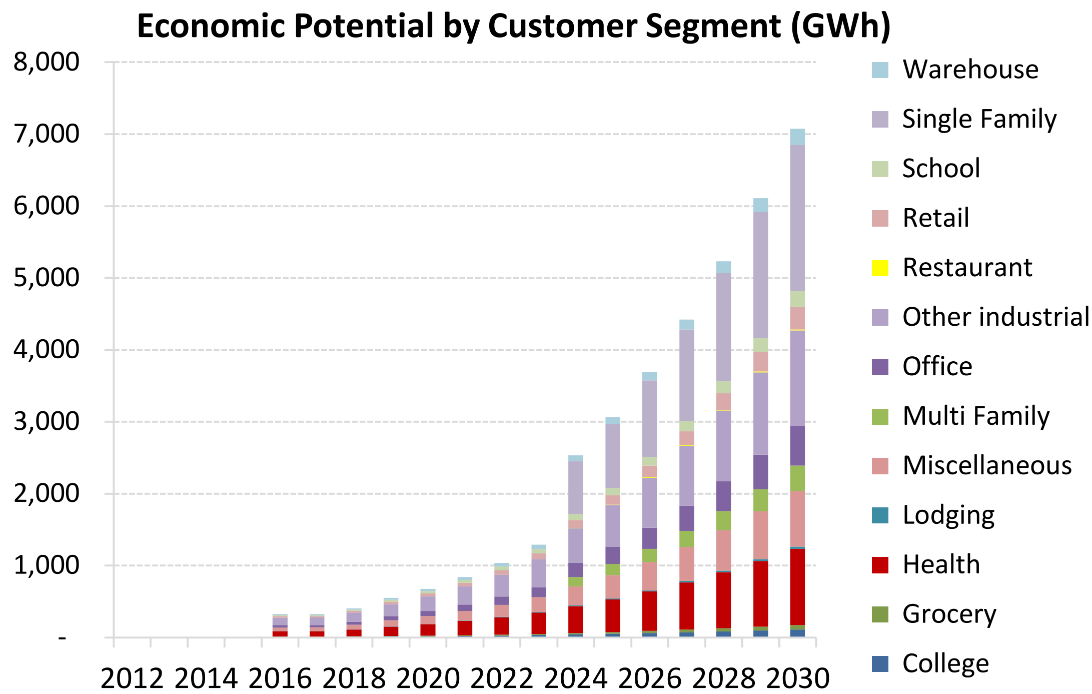
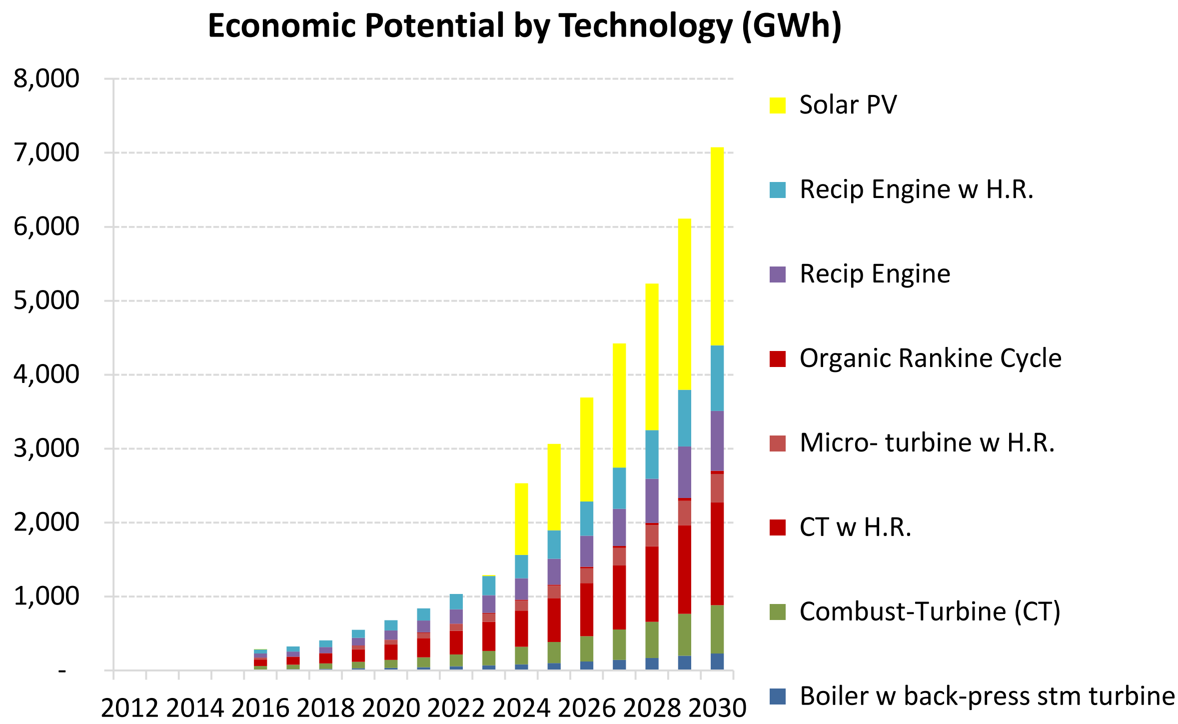


Table 4-6 shows the economic savings potential by technology and Figure 4-4 presents a graphical summary for the year 2016-2030. Despite heavy subsidies and declining costs, Solar PV is not cost-effective from a TRC perspective until 2026 for C&I and 2027 for the residential sector.

Table 4-6 DG-CHP Energy Economic Potential by Technology (GWh)

Technology	2016	2017	2018	2025	2030
Boiler w/ back-press stm turbine	15	18	23	99	230
Combustion Turbine (CT)	-	-	-	-	-
Combined Cycle CT	-	-	-	-	-
CT w/ Heat Recovery	23	29	36	157	360
Fuel Cell	-	-	-	-	-
Fuel Cell w/ Heat Recovery	-	-	-	-	-
Micro- turbine	-	-	-	-	-
Micro- turbine w/ Heat Recovery	-	-	-	-	-
Organic Rankine Cycle	-	-	-	-	-
Recip Engine	-	-	-	-	-
Recip Engine w/ Heat Recovery	19	24	31	133	890
Small Wind	-	-	-	-	-
Solar PV	-	-	-	-	2,679
Stirling Engine	-	-	-	-	-
Total	**57**	**72**	**90**	**389**	**4,159**

Figure 4-4 DG-CHP Energy Economic Potential by Technology (GWh)



PEAK LOAD SHIFTING ANALYSIS

This section describes the analysis approach and results for peak load shifting technologies.

Identify Relevant PLS Technologies

The first step toward estimating the potential of the PLS technologies was to identify the applicable technology options. Based on a thorough review of available and applicable technologies, as well as input from stakeholders, we arrived at the following list:

- Lead Acid Batteries
- Sodium Sulfur Batteries
- Li-ion Batteries
- Chilled Water Storage
- Ice Storage

The next step was to consider the size and applicability of a typical installation in each customer segment. This involved asking similar questions as those posed for DG-CHP technologies. If the technology was feasible and applicable, a system size was matched to the typical customers as shown by segment in Table 5-1. If a cell in the table does not contain a value, the technology is assumed to be inapplicable in that segment.

Table 5-1 PLS Applicability and Modeled System Sizes (kW) by Segment

Sector	Segment	Lead Acid Batteries	Sodium Sulfur Batteries	Li-ion Batteries	Chilled Water Storage	Ice Storage
Residential	Single Family	5	-	5	-	-
Residential	Multi Family	5	-	5	-	-
Commercial	Office	20	-	20	500	500
Commercial	Restaurant	5	-	5	-	-
Commercial	Retail	20	-	20	500	500
Commercial	Grocery	20	-	20	500	500
Commercial	College	20	-	20	500	500
Commercial	School	20	-	20	500	500
Commercial	Health	20	-	20	1,000	1,000
Commercial	Lodging	20	-	20	500	500
Commercial	Warehouse	20	-	20	500	500
Commercial	Miscellaneous	20	-	20	500	500
Industrial	Industrial	1,000	1,000	1,000	1,000	1,000

Characterize Typical PLS Installation

The next step was to consider and analyze a typical installation in each customer segment. This involved asking the following questions:

- What are the installation costs and annual O&M costs?
- What tax credits, state or regional rebates, or other economic incentives are available?
- What are the lifetime and typical annual operating hours?

The data to support this characterization is summarized in Table 5-2. The data sources correspond to the sources in the Data Development section of Chapter 2.

Table 5-2 PLS Technology and Cost Data

Technology	System Size (kW)	Lifetime	$/kW installed cost (2011)	$/kWh annual O&M (2011)	Load factor (% avail)	Federal tax credit	Installed Cost Decline from Yr 1 to YrFinal	Peak Coincidence Factor	Data Source
Lead Acid Batteries	5	8	$5,212	$0.008	25.0%	0.0%	0.0%	100%	2
Lead Acid Batteries	20	8	$5,175	$0.008	25.0%	0.0%	0.0%	100%	2
Lead Acid Batteries	200	8	$4,738	$0.008	25.0%	0.0%	0.0%	100%	2
Lead Acid Batteries	1,000	8	$2,884	$0.008	25.0%	0.0%	0.0%	100%	2
Sodium Sulfur Batteries	1,000	16	$3,708	$0.028	25.0%	0.0%	10.0%	100%	2
Li-ion Batteries	5	8	$4,018	$0.005	25.0%	0.0%	10.0%	100%	4
Li-ion Batteries	10	8	$2,842	$0.005	25.0%	0.0%	10.0%	100%	4
Li-ion Batteries	20	8	$3,148	$0.005	25.0%	0.0%	10.0%	100%	4
Li-ion Batteries	50	8	$4,067	$0.005	25.0%	0.0%	10.0%	100%	4
Li-ion Batteries	200	8	$2,940	$0.005	25.0%	0.0%	10.0%	100%	4
Li-ion Batteries	1,000	8	$14,700	$0.023	25.0%	0.0%	10.0%	100%	4
Chilled Water Storage	3,400	20	$745	$0.086	41.7%	0.0%	0.0%	100%	1
Chilled Water Storage	90	20	$1,370	$0.086	41.7%	0.0%	0.0%	100%	1
Chilled Water Storage	1,100	20	$568	$0.086	41.7%	0.0%	0.0%	100%	1
Chilled Water Storage	4,108	20	$388	$0.086	41.7%	0.0%	0.0%	100%	1
Chilled Water Storage	350	20	$293	$0.086	41.7%	0.0%	0.0%	100%	1
Chilled Water Storage	150	20	$730	$0.086	41.7%	0.0%	0.0%	100%	1
Chilled Water Storage	400	20	$372	$0.086	41.7%	0.0%	0.0%	100%	1
Chilled Water Storage	950	20	$754	$0.086	41.7%	0.0%	0.0%	100%	1
Chilled Water Storage	1,700	20	$384	$0.086	41.7%	0.0%	0.0%	100%	1
Chilled Water Storage	500	20	$398	$0.086	41.7%	0.0%	0.0%	100%	1
Chilled Water Storage	550	20	$412	$0.086	41.7%	0.0%	0.0%	100%	1
Chilled Water Storage	1,500	20	$290	$0.086	41.7%	0.0%	0.0%	100%	1
Chilled Water Storage	1,000	20	$712	$0.086	41.7%	0.0%	0.0%	100%	1
Chilled Water Storage	1,762	20	$627	$0.086	41.7%	0.0%	0.0%	100%	1
Ice Storage	1,055	15	$2,028	$0.086	41.7%	0.0%	0.0%	100%	1
Ice Storage	1,000	25	$2,700	$0.086	41.7%	0.0%	0.0%	100%	3
Ice Storage	1,500	25	$2,700	$0.086	41.7%	0.0%	0.0%	100%	3
Ice Storage	750	25	$2,700	$0.086	41.7%	0.0%	0.0%	100%	3

Key to data sources:

1. Statewide Joint IOU Study of Permanent Load Shifting, E3 and StrateGen, 2011	3. International Energy Storage Database, DOE
2. Electricity Energy Storage Technology Options, White Paper, EPRI, December 2010 Assessment, ICF International, 2012	4. KEMA/Sandia ES-Select Tool

PLS Potential Calculation and Results

The peak load shifting potential analysis follows the same process as the DG-CHP analysis described in the previous chapter except for one important variation. Peak load shifting technologies operate in a fundamentally different way than other DSM measures in that they shift energy usage from peak times to off-peak times. In order to make this a valuable opportunity, the price of electricity needs to vary with time of use. For this analysis, we applied a rate consistent with the time-of-use rate developed as described in the Volume 6 Demand-Side Rates report. This is a revenue neutral rate with avoided cost peak-time values three times the off-peak values and a peak period from 2:00pm to 7:00pm during the five summer months from June to October.

The technical potential for peak load shifting technologies in 2030 is to shift 4,328 GWh or 12.8% of load from on-peak to off-peak times, thereby reducing the system peak load by 1,396 MW or 17.9%. However, none of the technologies evaluated passed the economic screen, so there is no cost-effective achievable potential for utility programs to pursue. The TRC ratios at the beginning of the study period are in the 0.1 to 0.5 range and end in the 0.3 to 0.8 range. Table 5-3 and Table 5-4 summarize the results of the PLS savings potential analysis.

Table 5-3 Peak-Load Shifting Energy Impact Results (GWh shifted)

	2016	2017	2018	2025	2030
Baseline Forecast (GWh)	**30,249**	**30,449**	**30,694**	**32,228**	**33,721**
Cumulative Savings (GWh)					
Realistic Achievable	-	-	-	-	-
Maximum Achievable	-	-	-	-	-
Economic Potential	-	-	-	-	-
Technical Potential	272	341	427	1,869	4,328
Energy Savings (% of Baseline)					
Realistic Achievable	-	-	-	-	-
Maximum Achievable	-	-	-	-	-
Economic Potential	-	-	-	-	-
Technical Potential	0.9%	1.1%	1.4%	5.8%	12.8%

Table 5-4 Peak-Load Shifting Peak Demand Impact Results (Peak MW Reductions)

	2016	2017	2018	2025	2030
Baseline Forecast (MW)	**6,987**	**7,035**	**7,091**	**7,447**	**7,792**
Peak Savings (MW)					
Realistic Achievable	-	-	-	-	-
Maximum Achievable	-	-	-	-	-
Economic Potential	-	-	-	-	-
Technical Potential	88	110	138	604	1,396
Peak Savings (% of Baseline)					
Realistic Achievable	-	-	-	-	-
Maximum Achievable	-	-	-	-	-
Economic Potential	-	-	-	-	-
Technical Potential	1.3%	1.6%	2.0%	8.1%	17.9%

SENSITIVITY ANALYSIS

This chapter presents a sensitivity analysis to explore how results change with varying avoided costs. The alternate cost scenario, labeled Sensitivity in Figure 6-1, is the same one used in the EE analysis and has energy costs 30% higher than in the base case. As a result, DG-CHP economic potential increases, as shown in Table 6-1.

Figure 6-1 Avoided Cost Scenarios

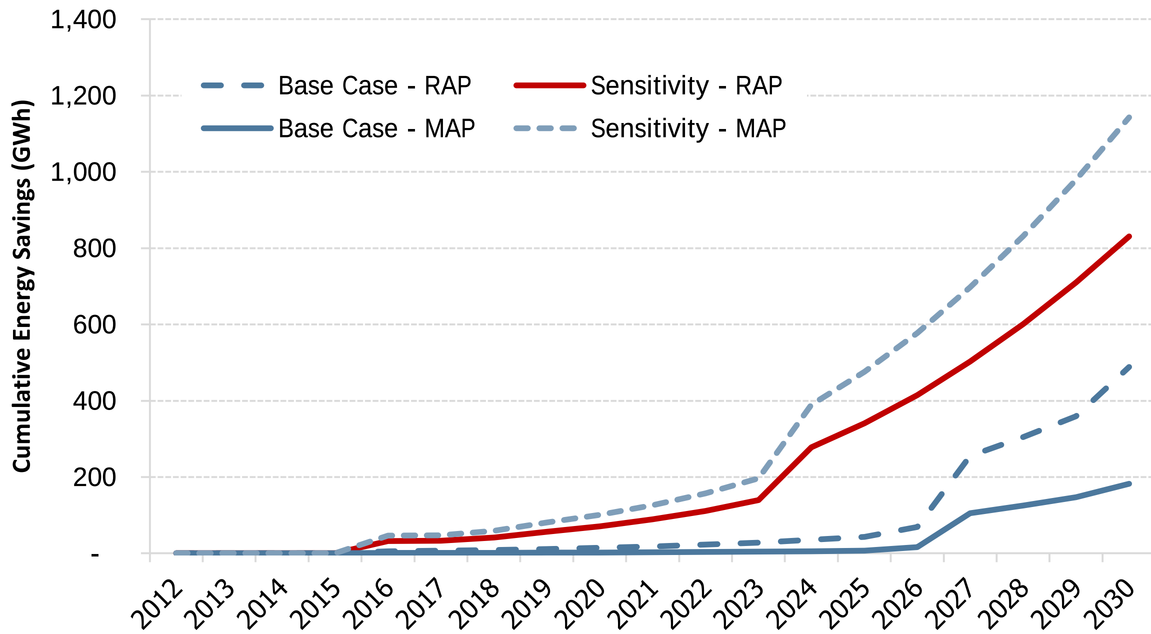
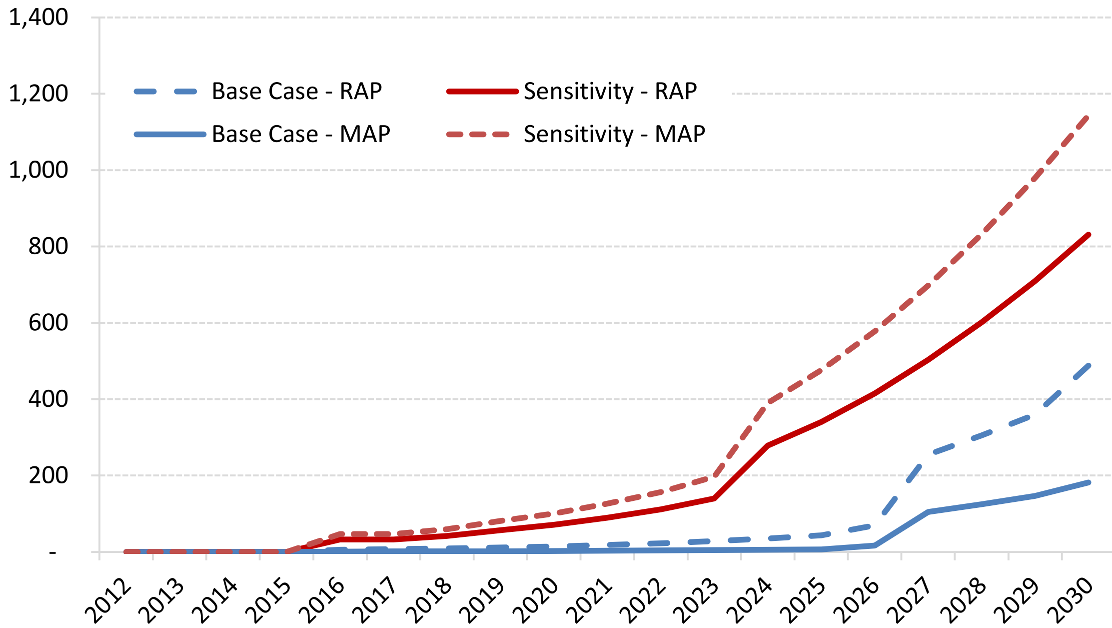


Table 6-1 Cost-effectiveness Results Comparison of Sensitivity Cases

	2016	2017	2018	2025	2030
Cumulative Energy Savings (GWh)					
Economic Potential Base Case	57	72	90	389	4,159
Economic Potential Sensitivity Case	324	323	404	3,065	7,076
Energy Savings (% of Baseline)					
Economic Potential Base Case	0.2%	0.2%	0.3%	1.2%	12.3%
Economic Potential Sensitivity Case	1.1%	1.1%	1.3%	9.5%	21.0%
Peak Savings (MW)					
Economic Potential Base Case	7	8	10	44	1,127
Economic Potential Sensitivity Case	37	36	45	630	1,447
Peak Savings (% of Baseline)					
Economic Potential Base Case	0.1%	0.1%	0.1%	0.6%	14.5%
Economic Potential Sensitivity Case	0.5%	0.5%	0.6%	8.5%	18.6%

Figure 6-1 shows the RAP and MAP potential for the two scenarios.

Figure 6-2 Sensitivity of Energy RAP and MAP Potential to Avoided Costs (GWh)



About EnerNOC

EnerNOC's Utility Solutions Consulting team is part of EnerNOC's Utility Solutions, which provides a comprehensive suite of demand-side management (DSM) services to utilities and grid operators worldwide. Hundreds of utilities have leveraged our technology, our people, and our proven processes to make their energy efficiency (EE) and demand response (DR) initiatives a success. Utilities trust EnerNOC to work with them at every stage of the DSM program lifecycle – assessing market potential, designing effective programs, implementing those programs, and measuring program results.

EnerNOC's Utility Solutions deliver value to our utility clients through two separate practice areas – Implementation and Consulting.

- Our Implementation team leverages EnerNOC's deep "behind-the-meter expertise" and world-class technology platform to help utilities create and manage DR and EE programs that deliver reliable and cost-effective energy savings. We focus exclusively on the commercial and industrial (C&I) customer segments, with a track record of successful partnerships that spans more than a decade. Through a focus on high quality, measurable savings, EnerNOC has successfully delivered hundreds of thousands of MWh of energy efficiency for our utility clients, and we have thousands of MW of demand response capacity under management.
- The Consulting team provides expertise and analysis to support a broad range of utility DSM activities, including: potential assessments; end-use forecasts; integrated resource planning; EE, DR, and smart grid pilot and program design and administration; load research; technology assessments and demonstrations; evaluation, measurement and verification; and regulatory support.

The team has decades of combined experience in the utility DSM industry. The staff is comprised of professional electrical, mechanical, chemical, civil, industrial, and environmental engineers as well as economists, business planners, project managers, market researchers, load research professionals, and statisticians. Utilities view EnerNOC's experts as trusted advisors, and we work together collaboratively to make any DSM initiative a success.

EnerNOC Utility Solutions Consulting
500 Ygnacio Valley Road, Suite 450
Walnut Creek, CA 94596

P: 925.482.2000
F: 925.284.3147