Evaluation Framework and Analyses for Thermal Energy Storage Integrated with Packaged Air Conditioning

Feitau Kung, Michael Deru, and Eric Bonnema
National Renewable Energy Laboratory

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Technical Report
NREL/TP-5500-60415
October 2013

Contract No. DE-AC36-08GO28308

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Prepared under Task No. BEC8.1122

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Printed on paper containing at least 50% wastepaper, including 10% post consumer waste.

Acknowledgments

The authors would like to thank the U.S. Department of Energy (DOE) Building Technologies Office for its support of the project. This report was prepared by the National Renewable Energy Laboratory (NREL) under Task Number BEC8.1122.

The authors greatly appreciated the valuable feedback about prior experiences, current industry needs, model approaches, and other grid considerations received from multiple individuals, including: Dennis Lilley, David Rubalcava, and Thomas Whitaker of Austin Energy; Eva Gardow of FirstEnergy; John Nix of Florida Power and Light; Bryan Cope of the Southern California Public Power Authority (SCPPA); Justin Hill of Southern Company; Ram Narayanamurthy of the Electric Power Research Institute (EPRI); Brian Parsonnet, Greg Tropsa, and Robert Willis of Ice Energy Technologies; and Stephen Frank, Edwin Lee, Ian Doebber, Paul Denholm, and Debra Lew of NREL.

The authors would like to thank Brent Griffith of NREL for his work in developing new thermal energy storage (TES) modeling capabilities in EnergyPlus that were critical for this project. The authors also thank EPRI, Ice Energy Technologies, and their respective commercial building and utility collaborators for providing performance data from sites with TES systems. The authors also would like to thank the following individuals for reviewing drafts of various sections of this document: Mark MacCracken of Calmac; Ram Narayanamurthy of EPRI; John Nix of Florida Power and Light; Brian Parsonnet and Robert Willis of Ice Energy Technologies; Bryan Cope of SCPPA; Justin Hill of Southern Company; and Stephen Frank, Brent Griffith, Bob Hendron, and Daniel Studer of NREL.

Executive Summary

Packaged air-conditioning (AC) systems are found in many commercial buildings. The Energy Information Administration estimated that in 2003, 1.6 million commercial, non-mall buildings in the United States were cooled with packaged AC units, and these buildings collectively represent about 30 billion ft^2 of floor space (EIA 2006). This suggests that if thermal energy storage (TES) can be cost effectively integrated with packaged AC, the technology's deployment potential could be high.

Few third-party guidance documents or tools are available for evaluating TES integrated with packaged AC, as this technology category is relatively new compared to TES integrated with chillers or hot water systems. To address this gap, a project was conducted to improve the ability of potential technology adopters to evaluate TES technologies. The target audience for this work includes engineers and analysts who evaluate commercial building technologies for building owners and utilities. Major project outcomes included:

1. An evaluation framework was produced to describe key metrics, methodologies, and issues to consider when assessing the performance of TES systems integrated with packaged AC.
2. The project applied multiple concepts from the evaluation framework to analyze performance data from four demonstration sites.
3. A new simulation capability was produced to enable modeling of TES integrated with packaged AC in EnergyPlus, a whole building energy simulation application that is available for free to the public. The new simulation capability will be included in EnergyPlus, version 8.1, in the fall of 2013. An early version of this feature was used to model one combination of a TES technology and control strategy. The performance of this application was simulated across multiple U.S. climate zones and three building types: office, stand-alone retail, and strip mall.

The analyses show that TES integrated with packaged AC can successfully shift electric demand and energy to off-peak hours in a variety of circumstances. Preliminary analyses show that such strategies can increase or decrease site energy consumption, depending on site-specific conditions. In either case, for a comprehensive assessment of TES impacts, site metrics must then be converted to source metrics; for such calculations, this report identifies methods, example sources of data, and needs for future improvements to public data that can be used to evaluate source metrics.

The analyses also indicate that emissions impacts are sensitive to hourly variations in load profiles. The results suggest that emissions and other source metrics may be sensitive to alternative control strategies that could be tested in the future to respond to real-time pricing signals, generate additional utility benefits, or improve renewable energy integration.

Nomenclature

AC	air-conditioning
AMPD	Air Markets Program Data
ASHRAE	American Society of Heating, Refrigerating and Air-Conditioning Engineers
BPA	Bonneville Power Administration
DOE	U.S. Department of Energy
DX	direct expansion
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
HVAC	heating, ventilation, and air-conditioning
NREL	National Renewable Energy Laboratory
PCM	phase change material
RTU	rooftop unit
TDSP	Transmission/Distribution Service Provider
TES	thermal energy storage

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1 Introduction

Packaged air-conditioning (AC) systems are found in many commercial buildings. The Energy Information Administration estimated that in 2003, 1.6 million commercial, non-mall buildings in the United States were cooled with packaged AC units, and these buildings collectively represent about 30 billion ft^2 of floor space (EIA 2006). This suggests that if thermal energy storage (TES) can be cost effectively integrated with packaged AC, the technology's deployment potential could be high.

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In this report, Sections 2.0 through 4.0 present the evaluation framework, which is intended to help prospective technology adopters assess potential implementations of such TES systems. Sections 5.0 and 6.0 present the results of example analyses of system performance for an ice-based TES technology. Additional methodology details are provided in the appendices.

Though the evaluation guidance and analysis results in this document focus on TES integrated with packaged AC units, some of the concepts are applicable to other energy storage technologies as well.

1.1 Target Audience

This document is written for two main audiences. First, the report provides methodologies for engineers who evaluate building technologies for commercial building owners. The framework will help this audience to evaluate site-level performance of TES systems and source impacts attributed to building-sited TES operation. The field data analysis and simulation analysis results illustrate how concepts and methodologies from the framework can be applied. Building owner engineers can apply methodologies in this report to evaluate the performance of other TES applications, and the results of such evaluations can inform assessments of the business case for potential investments in TES.

Second, the report provides introductory evaluation guidance for technical experts who assist utilities with technology evaluations and are considering distributed TES projects in collaboration with commercial building owners. The report explains analyses that can help to address operational and cost concerns of both utilities and building owners, and it suggests areas where future improvements to data would provide a more complete understanding of the impacts of TES.

1.2 Technology Basics

ASHRAE describes TES systems as those that "remove heat from or add heat to a storage medium for use at another time" (ASHRAE 2012, p. 51.1). A TES system can be *charged* by changing the temperature or phase of a substance in the storage section of the system. The system can be *discharged* by transferring heat between the storage section and a building load. TES systems can serve either cooling or heating needs, including space conditioning and process loads, though most use of TES today is for cooling applications (ASHRAE 2012).

One TES application is the use of ice storage for *peak load shifting*, which changes the timing of energy consumption for space cooling. The objective in this case is for a site to shift space cooling energy consumption from *on-peak hours*, when electricity demand from most utility customers is high, to *off-peak hours*, when electricity demand from most utility customers is low, such as during the night or early morning. During off-peak hours, when space cooling loads are also typically low, the TES system charges: electricity is consumed to drive a refrigeration cycle and freeze liquid water into ice. When space cooling is needed, the TES system discharges: the ice melts as heat from supply air is delivered to the ice. In many TES systems, including unitary TES systems integrated with packaged AC, charging and discharging typically involve circulating a heat transfer fluid between the TES system's refrigeration cycle equipment and its storage section (ASHRAE 2012). The energy required to pump and circulate heat transfer fluid during the discharging period is far lower than the energy required by the compressor for the refrigeration cycle during the charging period, so the bulk of the space cooling energy is consumed during off-peak hours.

In an ice TES system, water is also a *phase change material* (PCM) because it changes phase within the designed operating conditions of the system. During charging, liquid water undergoes sensible heat transfer until it reaches its freezing point, and then it undergoes latent heat transfer, releasing its heat of fusion at a constant temperature as it solidifies. In other TES applications, water may be designed to remain in its liquid state for sensible heat storage only, as in conventional tank water heaters, solar hot water storage, or chilled water storage for space cooling applications.

In the above case, water is the *storage medium*, the substance that maintains potential for later, controlled heat transfer when the substance is thermally discharged. Other storage media may also be used for TES. Selection of a storage medium will vary by application, but common considerations include availability, affordability, safety, stability, and favorable thermodynamic properties. Aside from water, thermal storage media can include other fluids (aqueous or nonaqueous); solids such as soil, rock, brick, ceramics, concrete, and components of a building structure; or other PCMs such as hydrated salts and polymers (ASHRAE 2012).

The analyses in this report examine an ice TES system, but the evaluation framework concepts and EnergyPlus simulation capabilities can also be applied to TES technologies that use liquid water or other storage media.

1.3 Potential Impacts

Potential TES impacts are generally connected with one or more of the following high-level considerations:

- **Capacity deferral or reduction.** Reduced peak power can decrease the cost of building or utility infrastructure.
- **Shifting the timing of loads.** The schedule and variability of loads affect utility decisions about which power generation systems to operate at different times. *Load leveling* can help utilities to operate generators more effectively and reduce congestion in distribution systems. Charging storage during off-peak demand periods and displacing loads during on-peak demand periods is an example of a load leveling application (Sioshansi et al. 2012).
- **Balancing and reliability.** For utilities, *ancillary services,* such as regulation and contingency reserves, "help grid operators maintain balance [between loads and generator output] on electric power systems" (NREL 2012). Utility-controlled, building-hosted TES systems could potentially help utilities to adjust the timing of electricity consumed by building systems that serve thermal loads, such as space cooling loads. For building owners, reliability needs may include on-site backup capabilities for critical thermal loads, such as cooling for data centers.
- **Source energy and emissions impacts.** Utility interests include optimizing the generation, transmission, and distribution of energy to reduce costs. Increasing efficiency will reduce fuel costs, but other cost-driven operational decisions can have different effects on system efficiency and source energy. Generation plant efficiencies and transmission and distribution losses vary with times of day and seasons of the year, and since TES measures change the timing of electricity consumption, TES evaluators may want to know whether particular applications have a positive, negative, or negligible impact on the site-to-source efficiency associated with consuming electricity to serve building thermal loads. Similarly, emissions associated with power use depend on when and where power is used. In addition to generation mix differences between utilities, each utility operates a different combination of its generation systems at different times.

These high-level considerations can be broken down into more specific potential technical and financial impacts listed in Table 1-1. Each impact conveys a different perspective or focus, though some necessarily involve overlapping concepts. The authors selected a subset of these impacts to target in this document based on: (1) the anticipated scope required to enable evaluation of the impact; and (2) the availability of relevant data from existing demonstration sites. Table 1-1 indicates which impacts are discussed in this document from either the building owner or the utility perspective.

Table 1-1 Summary of Potential TES Impacts

Integration of TES with packaged AC could impact the following:	Discussion included from the building owner perspective?	Discussion included from the utility perspective?
Peak power or electrical demand at the facility meter	Yes	Yes
Energy consumption at the facility meter	Yes	Yes
Demand and energy costs	Yes	Partly. This document describes the role of TES in utility arbitrage.
Source energy attributed to facility operations	Yes	Yes
Efficiency of utility power generation	Yes, in the context of site-to-source energy calculations.	Yes
Transmission and distribution losses	Yes, in the context of site-to-source energy calculations.	Yes
Emissions attributed to a facility's energy consumption	Yes	Yes
Effectiveness of renewable energy integration with loads and the electric grid	Yes	Yes
Sizing and installation of utility power generation, transmission, and distribution systems	N/A	Partly. This document explains an example case demonstrating an avoided cost.
Ancillary services, including regulation and contingency reserves	N/A	Partly. Interviewed utility representatives have not documented specific cases where this capability was enabled by TES integrated with packaged AC, but stakeholders are interested in testing this with future projects.

In general, energy storage systems can be marketed toward building owners, utilities, or both audiences, depending on the values that they offer. The following sections of this document discuss a variety of potential impacts and how different audiences may assess them.

1.4 Evaluating Performance at Different Levels of Detail

System characteristics discussed in this document can also be estimated at varying levels of detail, depending upon the evaluation objective.

1.4.1 General Performance Characteristics of Energy Storage Technologies

High-level performance results, such as demand and energy savings and associated cost savings, depend on a combination of site-specific conditions and technology-specific performance characteristics. Some performance characteristics are broadly applicable to many types of energy storage. These characteristics include:

- Storage capacity. This is generally expressed in terms of energy.
- Charging and discharging rates. These are generally expressed in terms of power.
- Ramp rate. This is the change in power charged or discharged over time to meet variations in power requirements (DOE 2010).
- Duration of time required for complete charging and discharging.
- Electric power input in different operational modes (e.g., charging only, discharging only, charging and discharging, idle) and different operating conditions (e.g., entering air temperatures and flow rates).
- Storage loss rate. This refers to energy losses from the storage section when it is partially or fully charged. The relationship between loss rates and environmental conditions will vary depending on the type of energy storage (thermal, electrochemical, etc.).
- Round trip efficiency. This is the useful energy discharged from storage divided by the energy input into storage during charging (DOE 2010).
- Capacity degradation. This refers to changes in capacity over multiple charge/discharge cycles. Some forms of energy storage, such as batteries, lose capacity over the life of the system, while other forms of energy storage can be charged and discharged without a capacity penalty.
- Cycle limitations on system lifespan. Whether or not there is a strong connection between an energy storage system's lifespan and charge/discharge cycles will depend on the type of energy storage. For example, the lifespan of an electrochemical battery system will likely be limited in terms of charge/discharge cycles, whereas the lifespan of a TES system could be limited by mechanical failure of a variety of components.
- Dispatchability. In the case of building-hosted systems, dispatchability can be characterized in terms of (1) energy storage product properties (e.g., capacity, maximum charging and discharging rates) that are largely independent of other building systems; and (2) schedule availability or flexibility constraints. The latter can depend on the timing of facility needs and interactions with other building systems.
- Downtime metrics. These may include: scheduled maintenance downtime; downtime associated with state of charge; unscheduled downtime; plant availability (reported at the end of operations); and the number and duration of failure incidents (DOE 2010).

- Ability to follow a control signal, such as an Automatic Generation Control (AGC) signal or an Area Control Error (ACE) signal. An example metric that quantifies this ability is the ratio of energy provided by the storage system divided by the energy required by the AGC or ACE signal at each 4-second interval; this was used in a program administered by the DOE Office of Electricity Delivery and Energy Reliability (DOE 2010).

Developers of specific programs that involve energy storage may include more or fewer metrics depending on the needs of the program. Some of these metrics also appear in technology-specific testing standards, which may specify testing conditions under which these metrics should be measured and reported.

1.4.2 Metrics for Standardized Product Testing and Performance Rating Specific to a Technology Category

Detailed data are necessary to describe the performance of specific technologies and products under standardized testing conditions. TES integrated with packaged AC is an example of a unitary system covered by American National Standard Institute (ANSI)/Air-Conditioning, Heating, and Refrigeration Institute (AHRI) Standard 900, which is titled the *2010 Standard for Performance Rating of Thermal Storage Equipment Used for Cooling* (ANSI 2011). This standard specifies multiple values that manufacturers must provide to accompany published performance ratings. This detailed class of metrics is important for ensuring that manufacturers and third-party testing organizations can collect product-specific performance data under controlled, standardized, laboratory conditions. The laboratory data can be used to inform the design of evaluation tools, which could range from spreadsheet calculators to more robust simulation programs, depending on the accuracy desired and the complexity of the systems under consideration. For example, the inputs used for simulations in this project were based in part on data collected under standardized testing conditions.

1.5 Timescales for Collecting Data or Reporting Metrics

For system performance data that can be viewed at different timescales, the decision to collect or report data at a particular timescale should take into account: (1) the audience for the data; (2) the accuracy or uncertainty of the values; and (3) the required effort or cost of data collection.

Within a building owner's organization, executive levels of management will likely be interested in annual values, such as total energy costs or savings, when making operational or procurement decisions. For facility managers, engineers, or energy consultants to conduct more detailed tasks, such as troubleshooting systems, optimizing controls, or estimating the performance of potential system purchases, more granular values are needed at hourly and subhourly timescales. These values may include time-series data—such as hourly or subhourly electricity demand—and values used to define system characteristics—such as the time required for an energy storage system to fully charge or discharge.

Though high-level reporting will often require summary values at annual or monthly timescales, the accuracy of such summary values will depend on underlying assumptions. For example, hourly data can enable estimation of energy cost savings for buildings with time-of-use tariffs. Similarly, hourly or subhourly data are important for estimation of demand savings, because monthly peak demand charges are often based on data collected at 15-minute intervals. More broadly, the decision to purchase a TES system integrated with AC may depend on an executive-level review of annual cash flows or life cycle costs, but the savings estimates will be based on energy performance calculations, which are more accurate when they account for hourly or subhourly building and system data.

On the other hand, the benefits of greater accuracy must be balanced with the required effort or cost of acquiring more granular data. For example, a comparison of annual source energy and emissions for two alternative systems may be important for some decision makers. Engineers or analysts who prepare such estimates may want to know whether annual average loss factors, efficiencies, or emission factors are adequate for such calculations, or whether seasonal average, hourly average, or hourly marginal factors are necessary to arrive at an accurate conclusion. Such considerations are discussed further in Section 3.0.

2 Evaluation Framework: Site Power, Site Energy, and Associated Costs

Site metrics:

- *Site power, including peak demand and the demand profile over time*
- *Site energy consumption*
- *Demand and energy costs to the building owner.*

The evaluation framework sections of this report describe key metrics, methodologies, and issues to consider when assessing the performance of TES systems integrated with packaged AC. When quantifying the impacts of building-sited energy storage on the electric grid, source metrics are more meaningful indicators of system performance than site metrics. Site metrics neglect impacts associated with off-site electricity generation and delivery, which vary with time; these off-site impacts are important for evaluations of energy storage, because energy storage technologies shift the timing of energy consumption. Nonetheless, some analysis of site metrics is also necessary because: (1) site metrics are connected to building owner's costs; and (2) measurements at the system or building level are needed to derive source metrics that can be attributed to specific building owners. This section (2.0) discusses site metrics in greater detail, and Section 3.0 describes conversions of site metrics into source metrics.

2.1 Rate Structure Variations

The cost effectiveness of energy storage depends in part upon utility rate structures. Some commercial building owners—typically those with smaller facilities—only pay energy charges for their electricity; other commercial building owners pay both demand and energy charges. In simpler rate structures, electricity charges may be fixed costs per unit of demand or energy. Some rate structures may also include a "ratchet" clause, which means that the minimum demand charge during any given billing period (e.g., for a particular month) is a certain percentage of the peak demand recorded during a longer period (e.g., the preceding 11 months).

In cases where rate structures vary demand or energy charges with time-of-use, the rate structures are simplified reflections of how utility operating costs vary between different times of day and different seasons of the year. "Time-of-use" rate structures may divide a day into different periods with different electricity charges, such as "off-peak," "partial-peak," and "on-peak" hours; they may also divide the year into different seasons with different electricity charges. These rate structures are one mechanism by which utilities can translate utility operational cost savings into building owner cost savings. The translation is not perfect, though, as time-of-use rate structures are only approximations of time-dependent variations in the cost of generating and delivering electricity.

A more sophisticated rate approach is "real-time pricing," which involves updating rates frequently, generally on an hourly basis (DOE 2013). For example, Southern California Edison's Real-Time Pricing RTP-2 rate structure option bills customers with "hourly electricity prices that vary based on time of day, season, and temperature," where prices during a particular day depend on temperatures recorded in downtown Los Angeles the previous day (Southern California Edison 2010). Residential real-time pricing structures in Illinois are even more closely matched to utility operational costs, "charging customers for the electricity they consume each hour based on the corresponding wholesale hourly market price of electricity" (Illinois Commerce Commission 2013). For commercial customers that maintain a 30-minute demand of 250 kW or more each month, Georgia Power offers day-ahead real-time pricing; for larger customers that maintain a 30-minute demand of 5 MW or more, it offers hour-ahead real-time pricing (Georgia Power 2013).

As time-based pricing options become more prevalent, time-dependent impacts of energy storage will likely increase the financial motivation for building owners to consider energy storage options. At present, though, not all building owners have access to time-based rate structures. More information about rate structures available through various utilities is available through the OpenEI Utility Rate Database at http://en.openei.org/wiki/Gateway:Utilities (Open Energy Information 2013).

2.2 TES Impacts on Site Demand and Energy

The ability of a particular TES technology to reduce electricity demand, energy, and associated costs varies with system design, environmental conditions, and local market factors. In the case of chiller-integrated TES systems, manufacturers have been able to build business cases with building owners who have access to time-of-use rates from their utilities. For example, the University of Central Florida estimated that its thermal energy storage facility, including a three million gallon tank that cost $3 million, will save close to $700,000 annually by shifting cooling loads to lower cost, off-peak periods (University of Central Florida 2013).

On the other hand, current rate structures for small commercial buildings may not yield enough savings to lead to wide-scale building owner investment in present-day TES systems integrated with packaged AC. An alternative approach is for building owners to partner with utilities that have other mechanisms for realizing savings from TES systems, as discussed in Section 4.0.

Regardless of which party purchases the TES system, the economic benefit to the building owner—which will be the primary motivation for a building owner to participate—will depend on capital costs and whether energy and demand charges increase, decrease, or stay the same when TES is added. Compared to a baseline system without TES, an alternative system with TES may consume more or less site energy, and several factors will contribute to the net result, including (but not limited to):

- The alternative system with TES may consume *less* energy than the baseline system if the alternative system operates its refrigeration cycle during periods when outdoor air temperatures are cooler. Faramazi et al. (2004) examined factors that affect the performance curves of packaged AC performance at high ambient temperatures and found that degradation rates vary with system design.
- The alternative system with TES may consume *less* energy than the baseline system if the TES system's compressor can be controlled to run constantly at or near its optimal efficiency point, whereas a constant-speed rooftop packaged AC unit may have to cycle to maintain space conditions and avoid overcooling.
- The alternative system with TES may consume *more* energy than the baseline system because the temperature difference between ambient air and the cold side of the alternative system is greater than the temperature difference between ambient air and the cold side of the baseline system.

- The alternative system with TES may consume *more* energy than the baseline system because the alternative system must compensate for heat transfer losses from the storage compartment, as well as limitations in the effectiveness of any additional heat exchangers.
- The alternative system with TES may consume *more* energy than the baseline system because additional circulation of heat transfer fluid requires additional pumping energy.

Reliable estimation of site power and site energy impacts from TES depends on access to reliable data for baseline and alternative system performance.

2.3 Basic Considerations for Reviewing Data from Prior Demonstrations

A detailed discussion of field monitoring is outside the scope of this document, but technology evaluators should be aware of the following basic considerations when reviewing the results of prior field demonstrations of TES integrated with packaged AC.

At a minimum, high priority system performance data to collect in field demonstrations include:

- Power and energy into the TES system
- Power and energy into the direct expansion (DX) packaged AC system (if separable from the TES system)
- Operational state of the TES system (charging, discharging, simultaneous charging and discharging, etc.)
- Operational state of the DX packaged AC system (cooling, idle, etc.).

Monitoring the above values at smaller time intervals will improve estimates of various TES impacts. When selecting a time interval (hourly, 15-minute, etc.) for estimating such values, considerations include:

- The energy data averaging interval used by the local utility to calculate peak demand
- The length of the TES system charge/discharge cycle
- The on/off cycling frequency of the packaged AC system under typical conditions
- How rapidly energy storage must be dispatched to provide functionality sought by the technology evaluator.

Additional site data may help reveal environmental or operational factors that can contribute to differences between baseline and alternative performance. A building owner's engineer may be able to use the additional site data to normalize performance values to account for differences in weather, facility schedules, or other variables. Such additional site data may include, but are not limited to:

- Indoor air conditions, such as dry bulb temperature and relative humidity, in the space served by the TES system
- On-site measurements of outdoor conditions, such as dry bulb temperature, relative humidity, and insolation. Outside air temperature can differ significantly between

rooftops and ground level, so temperature should be measured at the level where TES systems are mounted.

- Whole-building or whole-facility power consumption
- Heating, ventilation, and air-conditioning (HVAC) schedules, including setpoints and outdoor air fraction
- Operational schedules for other major building systems and occupancy schedules for the building
- Utility rate structures, which can influence how building engineers schedule and control systems
- Energy consumption of any major submetered end uses (if available). For example, changes to lighting and other internal loads can affect cooling loads.

The level of monitoring will depend on the objectives and scope of the demonstration; some projects may require more detailed data than those listed above, whereas other projects may have access to less data.

If a savings claim is made as part of a report from a field demonstration, it is important to understand how the baseline was defined as a part of that claim. There are several ways to collect field data that can be used with other information or modeling techniques to establish baseline system performance:

- If the HVAC system has been retrofitted to integrate TES without upgrading the efficiency of the DX packaged AC unit, then pre-retrofit data can be combined with other data (as described in Section 2.4) to estimate baseline performance.
- If the HVAC system is new, the monitoring period could be divided into two sets of days or weeks. One set would be the baseline set, during which the TES system is disabled, so that the baseline HVAC system provides all of the cooling. The other set would be the alternative set, during which the TES system operates as designed. The monitoring period should be subdivided in a manner that allows both sets to capture some similar weather and operating conditions.

In either case, when collecting field demonstration data, it is inherently difficult to control environmental and operational variations between baseline and alternative performance periods. Prospective adopters of a technology will therefore benefit from combining field data with laboratory data collected under more controlled test conditions. Preferably, the laboratory tests would be administered by a qualified, accredited third party in accordance with industry standards; in particular, TES integrated with packaged AC is an example of a unitary system covered by ANSI/AHRI Standard 900 (ANSI 2011). One effective method for analyzing a combination of laboratory and field data is to use them in coordination with whole-building energy simulation.

2.4 Combining Laboratory and Field Data with Simulations

Whole-building energy simulation programs can be used to assess how TES and HVAC systems perform under varying conditions. The TES and HVAC models in the energy simulation programs must have valid performance parameters and curves for the technologies being evaluated. Data collected under a range of controlled, laboratory test conditions should be used to generate individual performance parameters and curves that represent a physical system modeled by a simulation program.

Due to variability in environmental and operational conditions in the field, it is not the intent of such simulation to replicate field-measured performance precisely. Rather, such simulation aims to capture performance trends realistically enough to enable evaluation of relative performance of alternative systems. Field data can be used as a high-level check to see if a model is realistic given site-specific inputs that describe the facility, weather conditions, and key specifications of the evaluated technology, such as storage capacity, cooling capacity during discharge, electrical power input in different modes of operation, and charge and discharge times.

If the high-level check indicates that a model is realistic, a building owner's engineer may create variations on the original model to simulate performance for additional cases. Example applications include:

- If field data were collected for performance with TES, but not for a baseline case without TES, simulation can be used to estimate baseline system performance. This may be necessary if the HVAC system was either new or upgraded when the TES system was installed. Starting with a validated model of performance with TES, the modeler could remove the TES system and simulate performance with a DX-only cooling system.
    - If the TES system installation was paired with a replacement or upgrade for an old DX system that would have been replaced or upgraded anyway, then the old DX system should not be the basis of the baseline case. For a fair comparison, the DX units in the baseline case should have the same efficiency as the DX units in the alternative case.
    - If the TES system installation was paired with an early DX unit replacement or upgrade that would not have otherwise occurred, then the modeler has more choices. The modeler could consider the TES system and new DX unit to be two parts of a single energy measure package. From this perspective, the baseline case would reflect the efficiency of the old DX unit. The alternative case would reflect the combined costs and savings of the TES system and new DX unit. (Optionally, the modeler could create an additional alternative case for a comparison representing use of the new DX unit without TES.)
- If a monitoring period was divided into a baseline and an alternative set of days or weeks, then there will be inherent differences between the environmental and operational conditions of the baseline and alternative cases. Simulation can be used to produce two complete cases that span the same time period and are subject to the same environmental and operational conditions, making them easier to compare.
- Simulation can be used to predict how a system will perform in conditions that were not captured by a monitoring period. For example, if field data were collected for a year, simulations could be used to infer performance during hypothetical years with milder weather or more extreme events. These simulated years offer a more complete picture of future performance.

  The appropriate type of weather assumptions to select depends on the objectives of the building owner or utility that is considering TES. Varying weather assumptions can help a building owner or utility to construct a conservative savings estimate for a feasibility assessment or to compare the effectiveness of different options for critical load management under severe conditions. Typical meteorological year data, such as TMY2 and TMY3 data sets, are useful for simulating system performance during periods with common diurnal and seasonal variations, but these data sets do not capture meteorological extremes (Wilcox and Marion 2008); if a building owner or utility is considering TES as a resource for reducing cooling demand, it would also be useful to simulate system performance using weather data inputs that include some days that are hotter than those found in typical years.

- Simulation can also be used to estimate how performance would vary across different climates and applications.
- Simulation can also be used to estimate performance of alternative systems for a new construction project.

In combining laboratory and field data with simulations to compare baseline and alternative cases, an evaluator of a particular technology should also consider how the simulation platform represents the baseline system and how its approximations might affect the comparison of predicted results. Some limitations may be consequences of the simulation platform, while other limitations may result from a lack of adequate test methods for capturing and quantifying certain effects. One consideration is whether the evaluation approach can capture the difference in compressor cycling between baseline and alternative cases. Another consideration is whether the evaluation approach captures differences in dehumidification between the baseline and alternative cases, which would impact comfort. An awareness of these limitations will help a technology evaluator to determine whether an estimate of savings from a prospective TES technology is conservative or aggressive.

2.5 Coordination with Other Facility Needs

In some TES applications, the packaged AC system is sized such that it can handle the cooling load if the TES system is offline. Whether the DX equipment or associated electrical system infrastructure can be downsized relative to a baseline design depends on the specifications of the TES system and the specifications of how the TES will be committed to providing utility functionality. Similarly, if a building owner's engineer is considering integrating a TES system with backup cooling systems for critical loads, the design of any backup functionality will need to be coordinated with commitments to utility functionality. In evaluating whether separate functionalities can be coordinated, the technology evaluator will need to consider a variety of factors, including: the frequency, duration, and magnitude of utility-controlled discharge events; the capacity and charging and discharging times of the TES system; and any changes in electric demand from DX equipment in response to changes in TES system operation. Some constraints will be driven by physical conditions, while others may be set through contractual agreements. In the case of roof-mounted TES systems, a building owner's engineer will also need to determine whether the building can handle the additional structural load from a potential TES installation.

Compared to demand response programs, one advantage of integrating TES with cooling loads is that TES systems can be designed to have no impact on the thermal comfort of building occupants. Such arrangements change the timing of cooling energy consumption without changing when or how much cooling is delivered to conditioned spaces. A TES-based approach contrasts with traditional demand response strategies, which typically curtail the operation of one or more building services—such as cooling or lighting—during periods of particularly high electricity demand. Traditional demand response strategies can sometimes have a negative impact on occupant comfort and productivity, depending on the type, duration, and magnitude of the curtailment. A TES-based approach can provide utilities with demand reductions without disrupting other services to building occupants.

3 Evaluation Framework: Translating Site Impacts into Source Impacts

Source metrics:

- *Source energy (total or by fuel type)*
- *Source emissions*

Source energy and source emissions can be of interest to multiple audiences, each of which may have different assumptions about which factors in a site-to-source calculation can be simplified or should be scrutinized.

When evaluating a potential TES measure for a single, small commercial facility, the building owner's engineer can usually assume that installing TES at a single facility would not appreciably change a utility's current transmission and distribution loss factors, generation plant efficiency values, or source emission factors for different times of day. With this assumption, a building owner's engineer would apply loss, efficiency, and emission factors that reflect the current state of the grid when estimating source impacts. Researchers can help by producing or identifying simple tables of factors that can be used by building owners' engineers, because such engineers are unlikely to have access to or interest in using advanced grid analysis software to determine these factors.

For large commercial and industrial facilities, campuses, and residential communities, introducing large quantities of TES can begin to impact distribution loss factors. Additionally, a utility that is evaluating the aggregate impact of a large collection of sites with TES may want to use grid analysis software to assess whether high penetrations of TES systems will change transmission and distributions loss factors, generation plant efficiency values, source emission factors, or changes in generator unit commitment and dispatch.

There are many different methods of estimating source energy and emission factors for an electric power system, and the optimal approach will depend on how the factors will be applied. Adjustments can be made for transmission and distribution losses, as well as imports and exports to and from geographic regions of interest. Factors generated by these various methods generally fall into two categories:

- *Average* source energy and emission factors are based on average source energy or emissions per unit of electricity generation in the system over a stated period (sum of source energy or emissions divided by sum of generation). Average factors reflect a snapshot of the electric power system, so they are suitable for developing emissions inventories or estimating emission footprints associated with building owner operations.
- *Marginal* source energy and emission factors are based on the source energy consumption and emission rates of the generator(s) that are operated to provide more or less electricity in response to changing levels of demand. Marginal factors can be used to estimate the source energy and emission impacts of a project or policy that changes the system load (or generation) relative to a reference case, on a scale small enough not to change the mix of generators.

Users of these factors should be aware that it is not possible to measure the actual source energy consumption and emissions attributable to site energy use at any given time on the grid, so any source energy and emission factors are estimates of the real behavior. Load, generation, transmission, and distribution systems are very dynamic, and their interactions can only be approximated. Estimating marginal factors is more difficult than estimating average values as it is particularly difficult to predict the highly dynamic behavior of the grid in response to incremental changes in load. Therefore, it is recommended that marginal factors be used to approximate trends in behavior rather than absolute impacts.

3.1 Source Energy Calculations for Building Owners' Engineers

Building owners' purchasing decisions are primarily motivated by cost, but some building owners may also engage in initiatives to reduce the emissions impacts of their operations. Such building owner organizations may include private sector businesses that voluntarily pursue emissions reductions for social or marketing reasons. They may also include federal or other government agencies that are required to reduce emissions by law.

To calculate source energy, the building owner's engineer should start with hourly estimates of site energy consumption in case any time-of-use effects prove to be significant. If it turns out that site-to-source efficiency or loss factors vary significantly with time (e.g., varying with the hour of the day), the following calculation should be performed separately for each applicable time interval:

$$Source\ Energy = Site\ Energy \times SEF \qquad (3\text{-}1)$$

Where:

SEF = source energy factor

The authors recommend defining the source energy factor in a manner that accounts for losses that occur during four major stages of energy harvesting and delivery: distribution, transmission, generation (energy conversion at power plants), and precombustion (including extraction, processing, and transportation of fuels used in power plants).

To complete the site-to-source energy calculation, a building owner's engineer must find or derive appropriate source energy factors. These values can vary with regional generation mixes, local transmission and distribution system properties, loads, and environmental conditions, such as temperature. Unfortunately, hourly data or separate on-peak and off-peak values for efficiency and loss factors are often difficult to find. Before investing additional time in seeking new data, an engineer may want to know which of these efficiency and loss factors can be assumed to be reasonably constant and which factors can vary significantly by season or time of day. An exploration of example data that can influence such decisions is provided in Appendix A.

Average and marginal factors can also be used together to estimate the percent change in source energy for a particular project or policy. For example, given a baseline case and an alternative case, the following equations can be applied:

$$(Source\ Energy)_{Baseline} = (Site\ Energy)_{Baseline} \times SEF_A \qquad (3\text{-}2)$$

$$\Delta_{Source} = \Delta_{Site} \times SEF_M \qquad (3\text{-}3)$$

$$P_{Source} = \frac{\Delta_{Source}}{(Source\ Energy)_{Baseline}} \qquad (3\text{-}4)$$

Where:

Δ_{Site}	=	alternative site energy minus baseline site energy
Δ_{Source}	=	alternative source energy minus baseline source energy
P_{Source}	=	percent change in source energy relative to baseline source energy
SEF_A	=	average source energy factor
SEF_M	=	marginal source energy factor

3.2 Source Emissions Calculations for Building Owners' Engineers

Hourly estimates of site energy consumption can be multiplied by published hourly source emission factors to estimate source emissions associated with a baseline and alternative case. Emission factors are often published with units of emitted mass divided by energy, but the energy unit may be site or source energy, depending on the publication. Before using an emission factor, it is important to note which energy format is used. This document references data sources that present emission factors in the following form:

$$Source\ Emissions = Site\ Energy \times EF \qquad (3\text{-}5)$$

Where:

EF	=	emission factor (in units of emitted mass divided by site energy)

As with source energy factors, emission factors can be produced in two forms: average and marginal. These can be used together to estimate the percent change in emissions for a particular project or policy. For example, given a baseline case and an alternative case, the following equations can be applied:

$$(Source\ Emissions)_{Baseline} = (Site\ Energy)_{Baseline} \times EF_A \qquad (3\text{-}6)$$

$$\Delta_{Emissions} = \Delta_{Site} \times EF_M \qquad (3\text{-}7)$$

$$P_{Emissions} = \frac{\Delta_{Emissions}}{(Source\ Emissions)_{Baseline}} \qquad (3\text{-}8)$$

Where:

Δ_{Site}	=	alternative site energy minus baseline site energy
$\Delta_{Emissions}$	=	alternative emissions minus baseline emissions
$P_{Emissions}$	=	percent change in emissions relative to baseline emissions
EF_A	=	average emission factor
EF_M	=	marginal emission factor

One resource for finding hourly source emission factors is the OpenEI website, which includes a set of simplified lookup tables at http://en.openei.org/datasets/node/488 developed through a 2011 NREL project (Open Energy Information 2012). Resulting emission factors are provided in the form of pounds of power plant emissions per megawatt-hour of electricity consumed at a utility customer's site.

The developers of these tables combined demand profile data with simulation using an electric grid dispatch software package to estimate three types of emissions: carbon dioxide (CO_2), sulfur dioxide (SO_2), and nitrogen oxides (NO_x). The emission factors for sites in the U.S. eastern interconnection are based on 2005 demand profiles; emission factors for sites covered by the Electricity Reliability Council of Texas (ERCOT) and the Western Electricity Coordinating Council (WECC) are based on 2008 demand profiles. Multiple sets of emission factor values are provided to account for the following types of variations:

- **Location:** Emission factors are provided for 22 eGRID subregions spanning the 48 contiguous states of the United States (EPA 2012a).
- **Time of use:** For each location and each type of emissions, 12 month-specific sets of 24 hour-specific average emission factors are provided to capture variations across months of the year and times of day.

The OpenEI website provides access to average emission factors. Additional results from the 2011 project were leveraged to produce marginal emission factors used in Section 5.3. More details about the development of these factors are described in Appendix A.6.

Another source of average and marginal emission factors is the Greenhouse Gas Tool for Buildings in California, developed by E3 (2010). This spreadsheet tool includes hourly emission factors for the state of California based on 2008 data, and these factors were adapted for use in Section 5.3, as well. The spreadsheet tool and documentation of E3's methodology for estimating emission factors are available at http://www.ethree.com/public_projects/ghg.php.

4 Evaluation Framework: Utility Impacts and Collaboration with Building Owners

Key metrics:

- *Peak demand (monthly and average daily)*
- *Load factor*
- *Cost normalized by utility benefits (e.g., installed cost $ per unit peak demand reduction) compared to that of alternative utility investments*
- *Operational cost of providing a specific utility functionality (e.g., ancillary services) with or without energy storage*
- *Load match, grid interaction, and other metrics for sites with on-site renewable energy systems*

Understanding the potential for a technology to reduce source energy consumption and emissions is important to policymakers and regulators, but such metrics are only a part of a broader set of interests held by power system stakeholders. Other metrics are needed to characterize the potential for building-sited TES systems to reduce utility costs, including investments in infrastructure upgrades, purchases of electricity market products from electricity generators, and added costs from dispatching inefficient generators.

4.1 Potential Utility Benefits

A utility may evaluate an investment in a collection of distributed, building-hosted TES systems in comparison to other utility-scale investments, such as: (1) new generation, transmission, or distribution systems; (2) alternative demand response programs; or (3) other energy storage projects. Table 4-1 lists several potential utility benefits that have been suggested by prior publications related to energy storage, and it notes which functionalities have been demonstrated specifically using TES integrated with packaged AC, according to interviews conducted during this project with representatives of six utility organizations.

Table 4-1 Potential Utility Functionalities and Current State of Interviewee Application Using TES Integrated with Packaged AC

Functionality	Description	State of Interviewee Application
Avoided cost of new generation, transmission, or distribution systems	Investment in energy storage can be considered as an alternative to investment in new or larger generation, transmission, and distribution systems that would be implemented in response to rising demand requirements. From this perspective, alternative investments may be compared by metrics such as installed cost per unit of peak demand reduction.	One SCPPA interviewee reported a case of a utility with an overloaded feeder that wants to defer an upgrade of a substation (Cope 2013). The peak load shift enabled by installing TES integrated with packaged AC will provide the same benefit at a lower cost than the substation upgrade option.

Functionality	Description	State of Interviewee Application
Improved load factor	The load factor during a particular period of time is the average electrical demand divided by peak electrical demand; load factors can be calculated at various levels, such as at the building, facility, or utility scale. Buildings often have load factors around 0.5 (Barley et al. 2005).	One interviewee said that he sees upcoming installations of TES integrated with packaged AC as a part of the solution for improving a currently undesirable (low) load factor (Cope 2013).
Arbitrage	Energy arbitrage is the purchase of low-cost off-peak energy that can be resold during on-peak periods, and past research has examined the ability of electrical energy storage to facilitate arbitrage (Denholm et al. 2010; Sioshansi et al. 2009). In the case of TES, thermal energy is not typically sold, but arbitrage can be facilitated if TES is charged when electricity is less expensive and discharged when electricity is more expensive. Sioshansi et al. (2009) analyzed example cases in the territory of PJM, a regional transmission organization, to quantify how arbitrage values vary with application and time (by time of day and from year to year); they reported that the drivers of the arbitrage value of energy storage include location, fuel price, fuel mix, and the efficiency and size of the storage system. They also discussed a method for forecasting arbitrage value and demonstrate that a simplified backcasting approach was able to capture about 85% or more of the potential arbitrage value. They suggest that predictive accuracy could be improved through use of near-term weather forecasts and refined dispatch rules. Though the PJM analysis focused on electrical storage, the arbitrage value of TES technologies that shift the timing of electricity demand can be assessed in a similar manner.	Utility-scale arbitrage has been demonstrated using water heaters (Narayanamurthy 2013), but arbitrage benefits using TES integrated with packaged AC have not yet been documented quantitatively by interviewed utility representatives.

Functionality	Description	State of Interviewee Application
Ancillary services	Ancillary services "help grid operators maintain balance on electric power systems," and these services include regulation and contingency reserves (NREL 2012). Energy storage can facilitate regulation if the net output of a storage system can be adjusted "to ensure real-time balance between system energy supply and demand," which requires "a response time of seconds to minutes" (Sioshansi et al. 2012, p. 48). Energy storage can assist with contingency reserves if the net output of a storage system can be increased to respond to a contingency event, such as a transmission outage, with "a response time of minutes" (Sioshansi et al. 2012, p. 48).	One interviewee indicated that SCPPA member utilities are considering the use of ice TES to provide ancillary services (Cope 2013).

In addition to potential benefits that can be managed at the utility level, the benefits discussed in Section 4.2 are of interest to both building owners and utilities and represent opportunities for collaboration.

4.2 Load Leveling and Enhanced Renewable Energy Integration

TES systems offer the potential to change the profile of building energy loads by shifting the timing of certain loads. This potential can be described in terms of two applications: (1) load leveling; and (2) enhancing renewable energy integration.

Load leveling flattens load profiles and includes strategies that "[dampen] cyclical daily load flows" (EIA 2013). This can help utilities to operate generators more effectively and reduce congestion in distribution systems. TES systems integrated with packaged AC can facilitate load leveling by shifting the timing of cooling energy consumption. Building owners could theoretically take more actions to support load leveling, such as by implementing more energy storage or other demand response technologies, but they are not strongly incentivized to do so with current rate structures. Alternatively, if utilities control TES systems integrated with packaged AC, the economic benefit will vary depending on such factors as how quickly TES cooling potential can be dispatched, the magnitude of the change in cooling demand, and the relative contribution of cooling loads to overall loads for specific utilities.

Beyond traditional load leveling, TES integrated with packaged AC can potentially enhance renewable energy integration at multiple system boundary scales (e.g., utility, campus, building) and timescales (e.g., daily, hourly, subhourly).

- At the utility power scale, an aggregation of utility-controlled, building-hosted TES systems could allow utilities to compensate for variable renewable energy generation by adjusting the timing of electricity consumption from building AC systems. For instance, a utility with a surplus of off-peak electricity generation from wind power systems could charge ice or chilled water storage in building-hosted systems during off-peak hours, reducing the need to curtail off-peak wind power generation. This particular approach could be used with buildings that have cooling loads throughout the year. More generally, an effective solution will require alignment between the performance characteristics, controllability, and availability profiles of candidate storage, load, and generation systems.

- At the individual building scale, energy storage technologies like TES integrated with packaged AC could help smooth fluctuations in grid electricity demand from sites with on-site renewable power systems. Currently, owners of buildings and campuses may install on-site renewable power systems for environmental or life-cycle reasons, but they are not necessarily incentivized to integrate renewable energy in a manner that reflects an understanding of grid impacts. For example, design teams have been able to produce net zero energy buildings, but the buildings' imports and exports of energy are balanced on an annual basis, which is much longer than the balancing timeframes of interest to utilities. Owner-directed load-leveling practices could be encouraged by future rate structure revisions or incentive programs; or, utilities could apply the model of utility-owned, building-hosted equipment to larger systems that integrate loads, storage, and generation at building sites.

Prior research sponsored by the International Energy Agency (Voss et al. 2010; Salom et al. 2011) can serve as a starting point for analyzing potential metrics that could capture impacts of storage on renewable energy integration. For example, Voss et al. define a "load match index" that can be evaluated at different time intervals (e.g., monthly). Voss et al. offer a few variations on the load match index, depending on whether net metering is allowed and whether battery storage is present. If the "battery balance" term in one of their equations is replaced with the more general term, "energy storage discharge," a useful form of the load match index for evaluating TES would be:

$$f_{load,i} = \min[1, \frac{onsite\ generation + energy\ storage\ discharge}{facility\ load}], \tag{4-9}$$

where "i" denotes the time interval (e.g., hourly, daily, monthly).

Voss et al. also defined a "grid interaction index," f_{grid}, which reflects the stress that a building places on the electric grid if its import or export patterns fluctuate rapidly. In a review of multiple grid interaction indicators, Salom et al. (2011) include this version of the grid interaction index:

$$f_{grid,year} = standard\ deviation[\frac{E_i}{max(|E_i|)}], \tag{4-10}$$

where E_i is the net import of grid electricity over each interval i, and where $max(|E_i|)$ is the maximum value of E_i for the year. A negative value of E_i indicates a net export of electricity. A building with a relatively constant import or export pattern will have a low value for $f_{grid,year}$. Selecting a smaller timescale (e.g., one minute) for the interval i may be necessary if a site has large, rapid fluctuations in loads or on-site generation. An evaluator would then be able to assess whether fluctuations are severe enough to need mitigation and whether on-site storage, aggregation of distributed systems, or other load management strategies would be more effective.

Additional metrics may be necessary to adequately compare alternative designs. Such metrics could include the maximum rate of change in electricity imported to and exported from a site. These rates of change could be calculated as step changes between power values measured at time intervals relevant to utility operations and billing. For example, the step changes could be calculated at a 15-minute interval if that timescale is used by a local utility for calculating demand charges. Building industry representatives could work with utility representatives to determine the most relevant timescales and associated step change thresholds that would be beneficial not to exceed. These thresholds could be informed by ramp rates and costs of utility resources (e.g., regulation services) that would otherwise be needed to respond to net load fluctuations of a particular scale. Alternative building and system designs could then be evaluated in part on their ability to avoid exceeding key thresholds.

Table 4-2 lists potential impacts that could be evaluated in future research. Demonstration projects to date have not attempted to integrate control approaches for TES, packaged AC, and renewable generation systems with the intent of improving grid impacts of buildings that export renewable power. Future demonstration projects could be designed to quantify how the coordinated control of on-site generation, loads, and storage systems can optimize facility load profiles from a utility operations perspective.

Table 4-2 Potential Impacts of On-Site Storage on the Design and Operation of Facilities and Campuses with On-Site Generation

Possible Objectives for Integrating Storage with Distributed Generation	Utility-Level Questions	Facility-Level Questions	Possible Metrics and Scenarios to Compare
Maximize on-site generation while avoiding exports to the grid	When I allow a customer to export electricity, how do the benefits relate to the cost of required infrastructure investments, such as enabling bidirectional flow in applicable portions of the distribution system? How will these costs affect the price of energy exported from a customer's site? Once I have decided to allow a customer to export electricity, are there other export thresholds that would be undesirable to exceed (e.g., to maintain voltage requirements or comply with other regulations)? How might I incentivize building owners to avoid exceeding these export thresholds?	What is my on-site generation target? Which systems are critical to remain operational during a fault event on my utility's power system? For services that are non-critical but still highly beneficial (e.g., to maintain productivity), what is the value of ensuring that related systems remain operational? Will installing a different amount of on-site generation affect which rate structure applies to my facility? Can storage provide more consistent demand reductions by mitigating times when gross on-site generation is mismatched with load?	Facility energy metrics and on-site generation totals with and without storage. Incremental cost of storage versus incremental cost to the utility for regulation resources or curtailment. Cost to building owner of building system design options sized with and without storage. Peak electricity demand with and without storage. Peak electricity export with and without storage.

Possible Objectives for Integrating Storage with Distributed Generation	Utility-Level Questions	Facility-Level Questions	Possible Metrics and Scenarios to Compare
Minimize unexpected variability in net load profiles	What are the costs of alternative strategies (e.g., regulation resources) for mitigating variability in net load profiles? Will storage help customers to participate more effectively in load management programs?	Will a particular storage technology pay back with current rate structures and incentives, or do I need to partner with a utility that can own and control the storage asset?	Incremental cost of storage versus incremental cost to the utility for regulation resources, curtailment, or generation assets. Maximum step changes in electricity imports to and exports from a site with and without storage. Load match metrics with and without storage. Grid interaction metrics with and without storage.
Minimize investment in distribution infrastructure	What are the costs of alternative strategies (e.g., infrastructure investments) for relieving a system constraint that is limiting deployment of new loads or distributed generation?	Will design alternatives affect how much the utility will charge me to connect new loads or on-site generation with the grid?	Peak electricity demand with and without storage. Peak electricity export with and without storage.
Optimize real-time pricing to maximize returns	How well does the customer's electricity tariff reflect utility-level market prices for power generation and distribution? Would alternative pricing structures provide greater opportunity for arbitrage? Are any infrastructure upgrades (e.g., communications, metering) required to implement real-time pricing?	Which loads in my facility can be scheduled in a flexible manner? Will varying the operation of certain building systems affect the performance of other systems through interactive effects? Will participation reduce my electricity costs?	Savings potential from participating in real-time pricing structures with and without storage. Availability and output of storage capacity by hour under different control schemes.

Possible Objectives for Integrating Storage with Distributed Generation	Utility-Level Questions	Facility-Level Questions	Possible Metrics and Scenarios to Compare
Respond to utility control signals to provide ancillary services	What are the constraints on the availability of this resource for responding to utility control signals? If there is a market for ancillary services in my region, what types of resources are eligible for participation?	Which loads in my facility can be scheduled in a flexible manner? Which systems in my facility could respond to utility control signals without affecting services to occupants? Will participation reduce my electricity costs?	Load match metrics with and without storage. Grid interaction metrics with and without storage. Availability of storage capacity by hour under different control schemes. Maximum charge and discharge rate in response to utility control signals.

4.3 Alternative Models for Building Owner Participation

Broad deployment of strategies that integrate on-site storage with generation will depend on the availability of adequate rate structures, incentive programs, or partnerships that benefit both utilities and building owners.

As discussed in Section 2.0, facility-level savings under current rate structures may not be sufficient to lead to wide-scale building owner investment in presently available TES systems integrated with packaged AC. As time-based pricing options become more prevalent, however, more building owners are likely to consider technology options that can support load management strategies.

In the near term, other methods for utilities to engage building owners include developing incentive programs or forming direct partnerships with building owners who are willing to share responsibilities for TES systems with utilities. For instance, one TES manufacturer has developed a marketing approach directed toward utilities (Ice Energy 2012) in which building owners host TES systems that are owned and maintained by the utility at little or no cost to the building owners. Both the building owners and the utility would be interested to know whether the system results in energy and demand savings, but the utility would be the primary party concerned with recovering the system installation cost. The utility could recover the TES installation cost through several means, such as energy arbitrage or avoided capital investments enabled by reducing peak demand. Feasibility for a specific utility would need to be analyzed on a case-by-case basis.

In some of these partnerships, the utility controls the distributed TES systems and could potentially realize additional benefits described in Section 4.1, such as ancillary services. Additionally, the use of utility-controlled distributed TES systems is not limited to projects that integrate TES with packaged AC. For instance, Bonneville Power Administration has explored the feasibility of integrating utility control with other end uses, such as hot water heaters, that consume electricity and have thermal storage capacity (Ecofys 2012). Other utility stakeholders have also implemented demonstrations of distributed hot water TES.

5 Analysis of Performance Data from Demonstration Sites

This section presents the results of applying multiple concepts from Sections 2.0 through 4.0 to evaluate the performance of TES systems from example demonstration sites. At the selected sites, TES systems and monitoring equipment had been installed as part of activities separate from the DOE/NREL project. NREL worked with industry partners to identify four sites where stakeholders were willing to share anonymous performance data with NREL for an analysis that could be shared with the public. Cost impacts are not included here due to data limitations, but demand and energy impacts are presented for all four sites, and emissions impacts are presented for sites with adequate data.

At each of the four sites, baseline data were not collected by the technology developer or the building owner, so the authors have separately estimated baseline performance. As discussed in Section 2.3, there are several methods for establishing a baseline, such as by (1) combining pre-retrofit data with simulation, or by (2) dividing a monitoring period into baseline and alternative periods of days or weeks. In the case of the demonstration sites in this project, however, pre-retrofit data were not available, and the monitoring period did not include any baseline days.

Instead, the authors employed a third approach to estimate DX power and run times in different modes of DX operation for the baseline case. One-minute measurements of DX power were binned into three groups based on which mode of operation the DX system was in when each measurement was taken. The three modes were "cooling," "fan," and "idle." The group of minutes in DX cooling mode was further subdivided into two groups, depending on whether or not the DX system was transitioning between modes.

DX power values during non-transitional cooling minutes were then correlated with ambient air temperature measurements to produce a simplified linear regression model of baseline performance for that mode of DX operation. For other modes of DX operation, average power values were estimated.

Fractional run times were estimated for each mode of DX operation, using separate assumptions to define representative periods for estimating maximum and average DX power. The baseline power values for different modes were combined with the estimated fractional run times to estimate overall power for 15-minute periods used in peak demand calculations and one-hour periods used in average energy calculations. A detailed discussion of the baseline assumptions and development method is provided in Appendix B.

5.1 Site Performance Data from Project Partner 1

A TES technology developer, Ice Energy Technologies, provided a year of TES and DX system performance data that it had collected in 2012 at two buildings in California. The buildings were in different cities, but both are located within Climate Zone 3B as defined by DOE and ASHRAE. (Climate zones are described in more detail in Section 6.2.1.)

At both sites, each TES unit has a cooling capacity of five tons and a storage capacity of 30 ton-hours, and each TES unit is integrated with a DX unit that also has a cooling capacity of five tons. Major components contained in each TES unit include: an ice storage section with a heat exchanger; a condensing unit with a heat exchanger; an R-410A refrigerant compressor; and a controller.

Each site has multiple TES units in operation, and Ice Energy Technologies provided performance data for one representative TES unit and DX unit per site. Ice Energy Technologies also provided on-site measurements of outside air temperature taken near the TES and DX units; this was helpful for reducing analysis error, because temperatures in rooftop microclimates can be several degrees higher than temperatures at ground level.

Basic characteristics for each site are summarized in Table 5-1.

Table 5-1 Demonstration Sites 1 and 2

Case	Site 1	Site 2
State	California	California
Climate Zone	3B	3B
Facility Type	Commercial office	Commercial office
Facility Size	One story; 3,300 ft^2	One story, 21,000 ft^2
Facility Vintage	2004	2010
HVAC System Vintage	2004	2010
Total Installed HVAC Cooling Capacity	10 tons	55 tons
Capacity of Each DX Unit	5 tons	5 tons
Number and Location of DX Units	2 units; ground-mounted	11 units; rooftop-mounted
Number and Location of TES Units	2 units (one TES unit integrated with each DX unit); ground-mounted	11 units (one TES unit integrated with each DX unit); rooftop-mounted
Utility	Pacific Gas & Electric	California municipal utility
Demand Charge Rate Structure	A-10 TOU Medium General Service	Municipal Electric Utility Large Commercial Tariff
Monitoring Period for This Study	January 1, 2012 to December 31, 2012	January 1, 2012 to December 31, 2012

5.1.1 Site 1

An example day of performance data for one TES unit paired with one DX unit at Site 1 is shown in Figure 5-1. The 24-hour period starts at 12:00 p.m. (noon) to coincide with the scheduled start time for TES discharge, allowing the figure to depict a complete discharging and charging cycle. To mirror typical utility approaches for calculating electricity demand, the maximum power value for each hour was estimated by averaging power measurements over 15-minute intervals and selecting the greatest 15-minute average recorded in that hour.

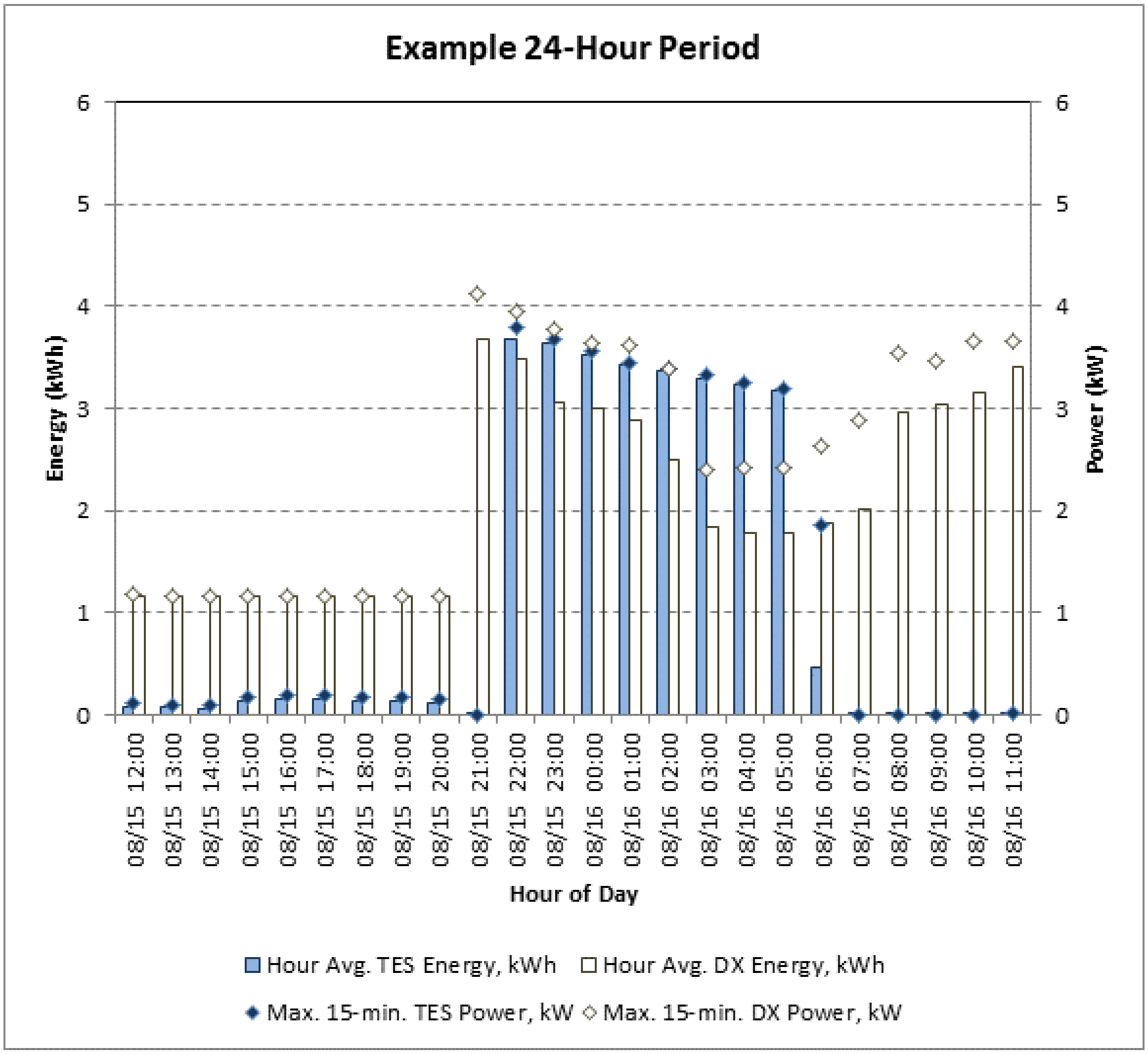

Figure 5-1 Example 24-hour period of performance data from Site 1

At Site 1, most instances of TES cooling occurred between 12:00 p.m. and 9:00 p.m., reducing the average electrical energy consumption and maximum electrical demand during that time. The first six hours of this window (12:00 p.m. to 6:00 p.m.) are the times of day designated by the building's utility tariff to be in the "Summer Peak Period," when energy rates are highest. Utility tariff periods are summarized in Table 5-2.

Between 9:00 p.m. and 12:00 p.m., when energy rates are lower, electricity demand and energy consumption values at Site 1 are higher, reflecting times when the DX system provides cooling and times when the TES system charges.

Table 5-2 Tariff Periods at Site 1

	Summer Off-Peak Period	Summer Partial-Peak Period	Summer Peak Period	Winter Off-Peak Period	Winter Partial-Peak Period
Days of the Year	May 1 through October 31			November 1 through April 30	
Days of the Week	Saturday, Sunday, and holidays	Monday through Friday (except holidays)		Saturday, Sunday, and holidays	Monday through Friday (except holidays)
Times of Day[1]	9:30 p.m. to 8:30 a.m.	8:30 a.m. to 12:00 p.m., and 6:00 p.m. to 9:30 p.m.	12:00 p.m. to 6:00 p.m.	9:30 p.m. to 8:30 a.m.	8:30 a.m. to 9:30 p.m.

Site 1 system performance during the various tariff periods is depicted in Figure 5-2 through Figure 5-5. Key values are summarized in Table 5-3 through Table 5-5. TES successfully shifted electricity demand and energy consumption from summer peak tariff hours to summer partial-peak and off-peak tariff hours. Winter electricity demand for the case with TES is greater than baseline winter electricity demand due to infrequent use of TES, but winter energy use for both cases is approximately equivalent. Total annual cooling electricity consumption was estimated to be about 2% greater than baseline electricity consumption, but the difference is small relative to the uncertainty associated with the estimates of baseline performance described in Appendix B.

[1] The tariff also specifies that these start and stop times all are shifted one hour later during two periods of the year: (1) between the second Sunday in March and the first Sunday in April; and (2) between the last Sunday in October and the first Sunday in November.

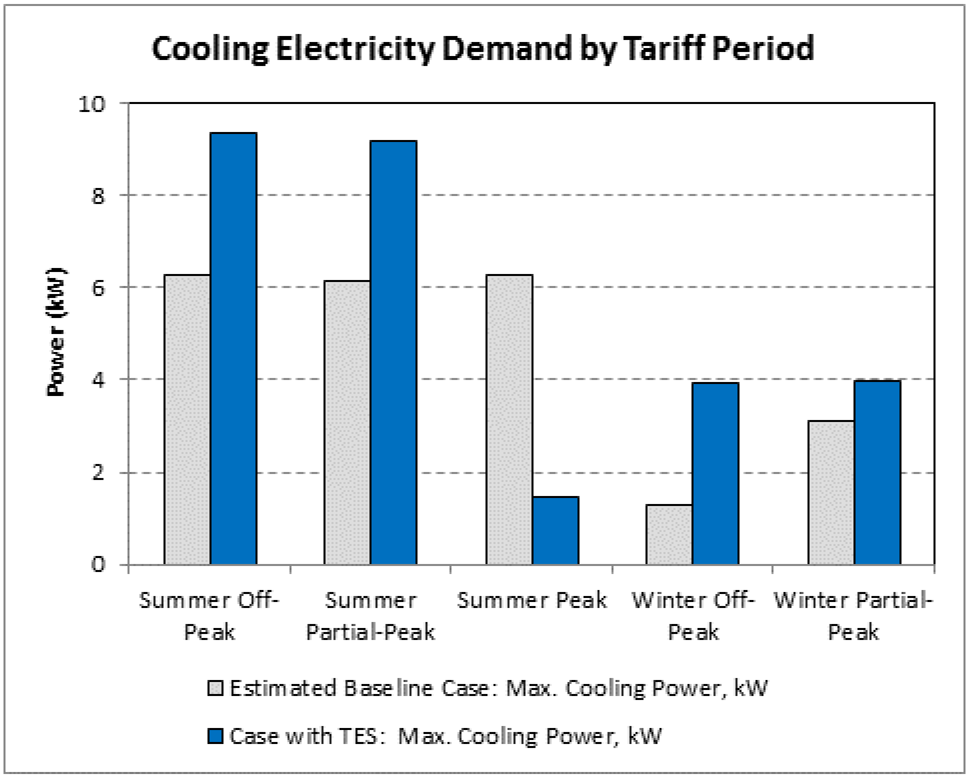

Figure 5-2 Cooling electricity demand by tariff period for Site 1

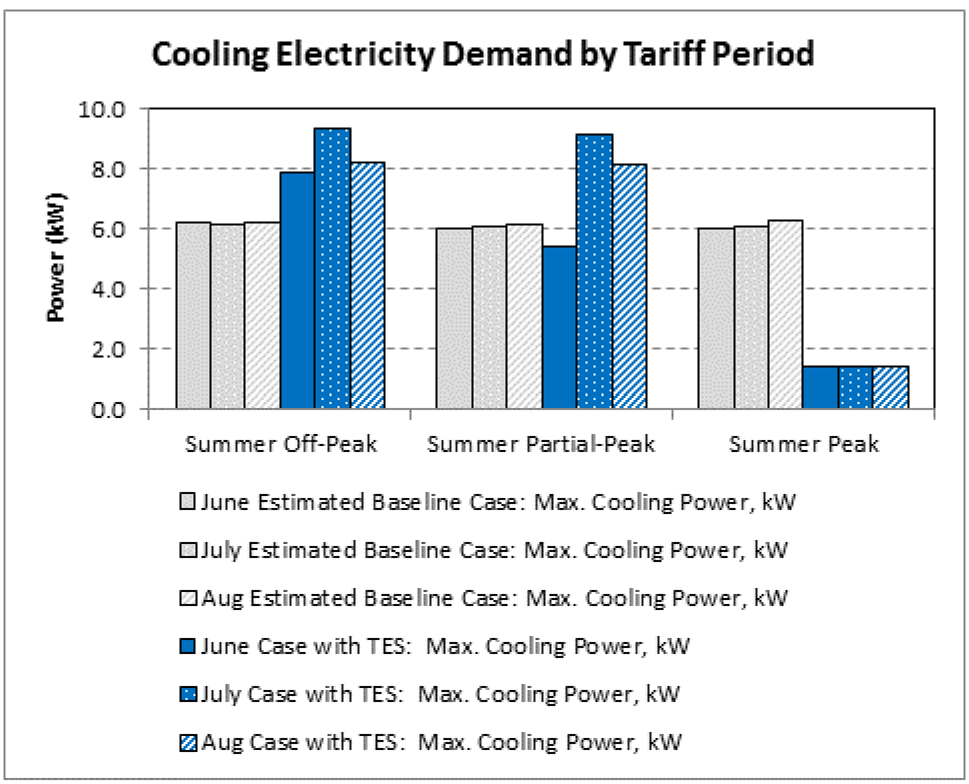

Figure 5-3 Summer cooling electricity demand for Site 1

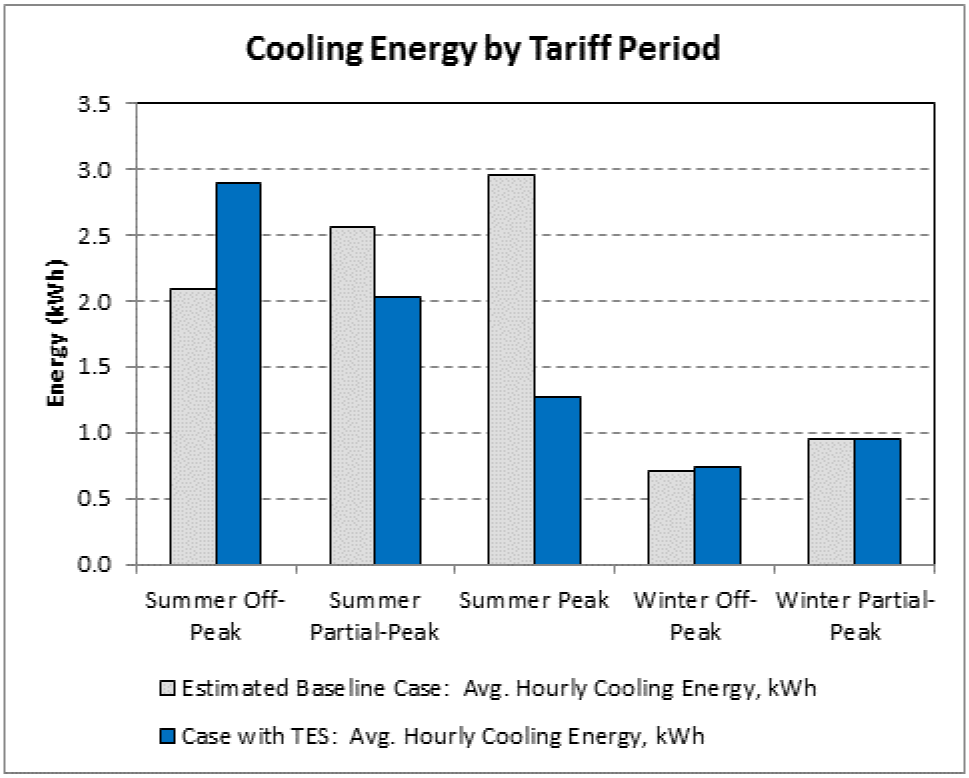

Figure 5-4 Cooling energy by tariff period for Site 1

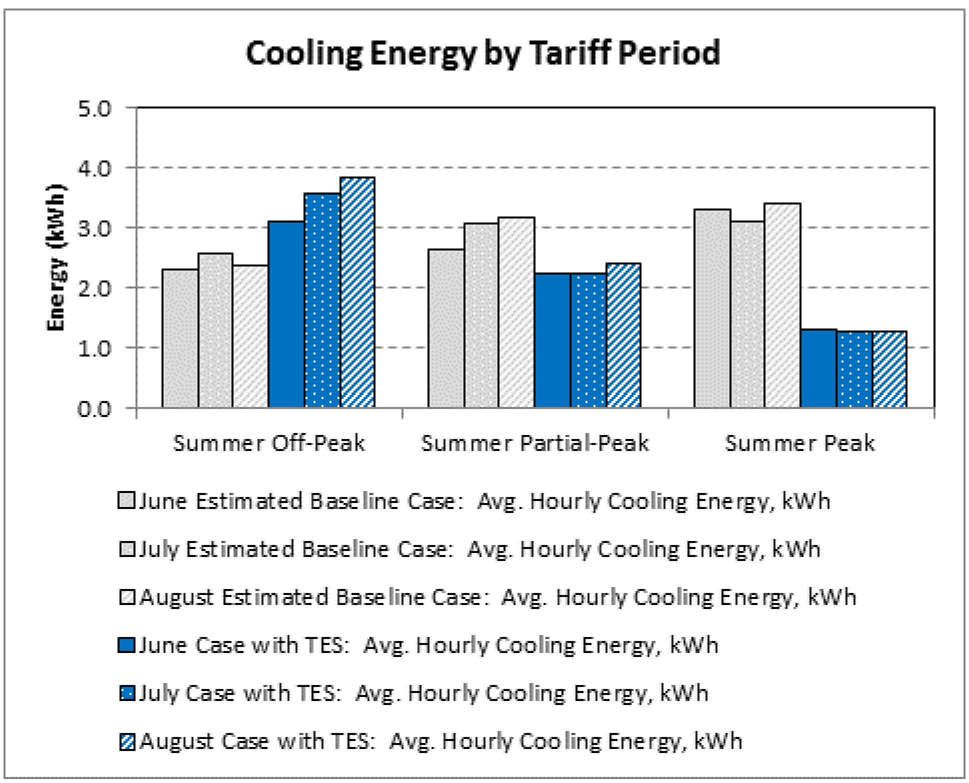

Figure 5-5 Summer cooling energy for Site 1

Table 5-3 Cooling Electricity Demand at Site 1

	Summer Off-Peak Period	Summer Partial-Peak Period	Summer Peak Period	Winter Off-Peak Period	Winter Partial-Peak Period
Observed Case: Max. TES Power, kW	4.04	4.00	0.26	2.79	2.77
Observed Case: Max. DX Power, kW	5.63	6.01	1.23	1.27	1.26
Observed Case: Max. Cooling Power, kW	9.34	9.16	1.45	3.91	3.98
Estimated Baseline Case: Max. Cooling Power, kW	6.26	6.15	6.29	1.27	3.09

Table 5-4 Cooling Electricity Average Energy Consumption at Site 1

	Summer Off-Peak Period	Summer Partial-Peak Period	Summer Peak Period	Winter Off-Peak Period	Winter Partial-Peak Period
Observed Case: Hourly Average TES Energy, kWh	1.13	0.05	0.09	0.03	0.01
Observed Case: Hourly Average DX Energy, kWh	1.76	1.98	1.18	0.71	0.94
Observed Case: Hourly Average Cooling Energy, kWh	2.90	2.03	1.27	0.74	0.95
Estimated Baseline Case: Hourly Average Cooling Energy, kWh	2.08	2.55	2.95	0.71	0.94

Table 5-5 Cooling Electricity Annual Energy Consumption at Site 1

	Summer Off-Peak Period	Summer Partial-Peak Period	Summer Peak Period	Winter Off-Peak Period	Winter Partial-Peak Period	All Periods
Observed Case: Hourly Average Cooling Energy, kWh	6,701	1,887	893	1,719	1,450	12,651
Estimated Baseline Case: Hourly Average Cooling Energy, kWh	4,815	2,372	2,079	1,651	1,445	12,362

5.1.2 Site 2

A similar control strategy was employed at Site 2, though the TES discharge window was shorter; an example day of performance data for one TES unit paired with one DX unit at this site is shown in Figure 5-6. The figure starts at 12:00 p.m. (noon), which is the start of the discharge window, so that it can depict a full discharging and charging cycle.

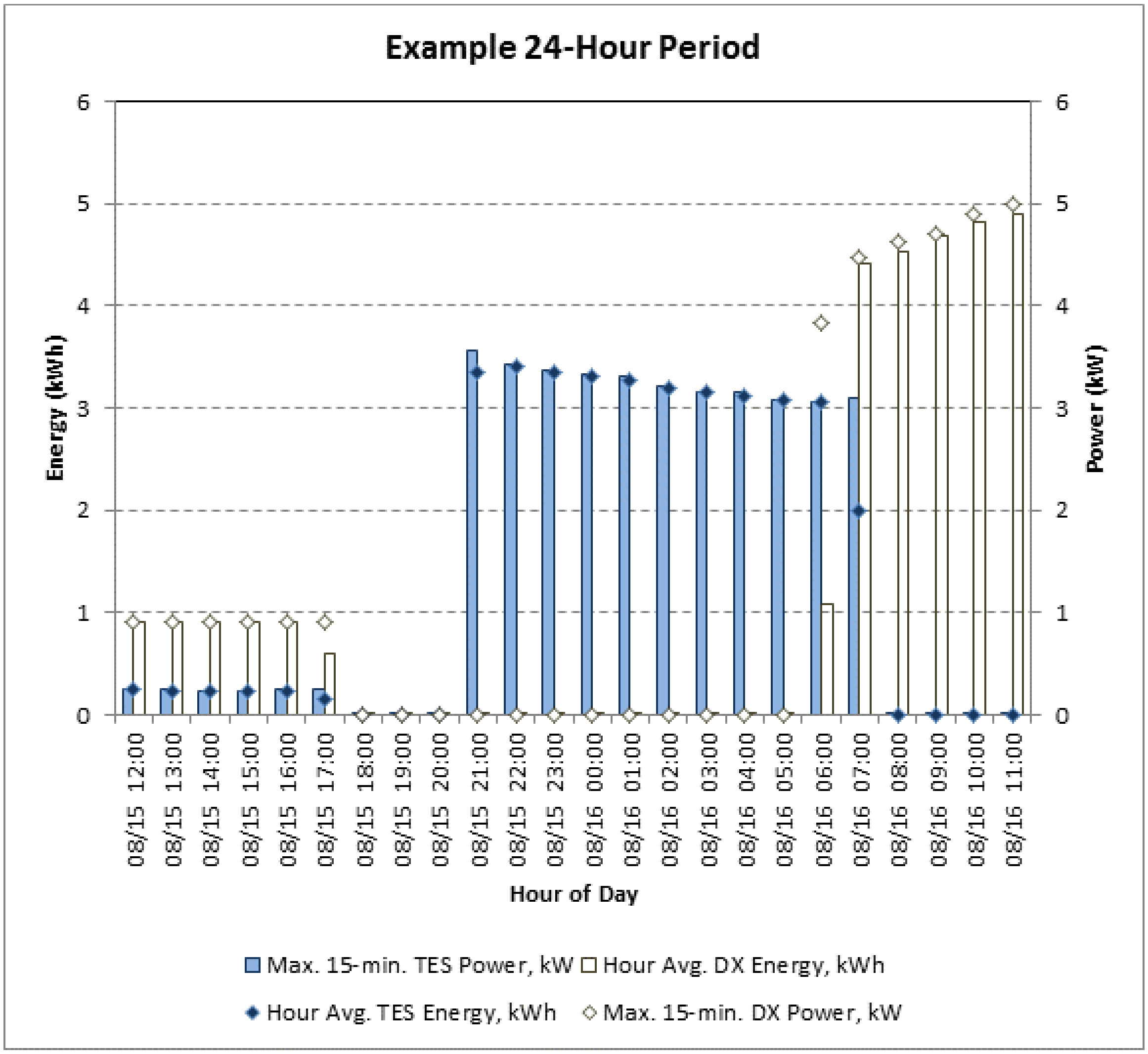

Figure 5-6 Example 24-hour period of performance data from Site 2

Unlike Site 1, at Site 2, the electricity tariff did not include time-of-use charges. The TES technology developer also reported that this particular TES application was focused on reducing demand during summer months. To maximize demand savings, the TES systems were intentionally paired with high efficiency rooftop units (RTUs). The majority (97%) of the instances of TES discharge occurred in the afternoon between 12:00 p.m. and 5:59 p.m., so Figure 5-7 and Figure 5-8 summarize cooling system demand and energy consumption based on whether the values fell inside or outside this period of the day. Key values are summarized in Table 5-6 through Table 5-8.

Cooling demand at this site was successfully shifted out of afternoon hours, which is when most office buildings in this location would be expected to have high electric loads. Total annual cooling energy consumption with TES was estimated to be about 11% greater than baseline energy consumption. An increase in site energy consumption is more likely if a case with TES is compared to a baseline with a high-efficiency RTU, as was the case for Site 2. The technology developer reports that other TES projects have typically been energy neutral or better in cases where the baseline used standard efficiency RTUs.

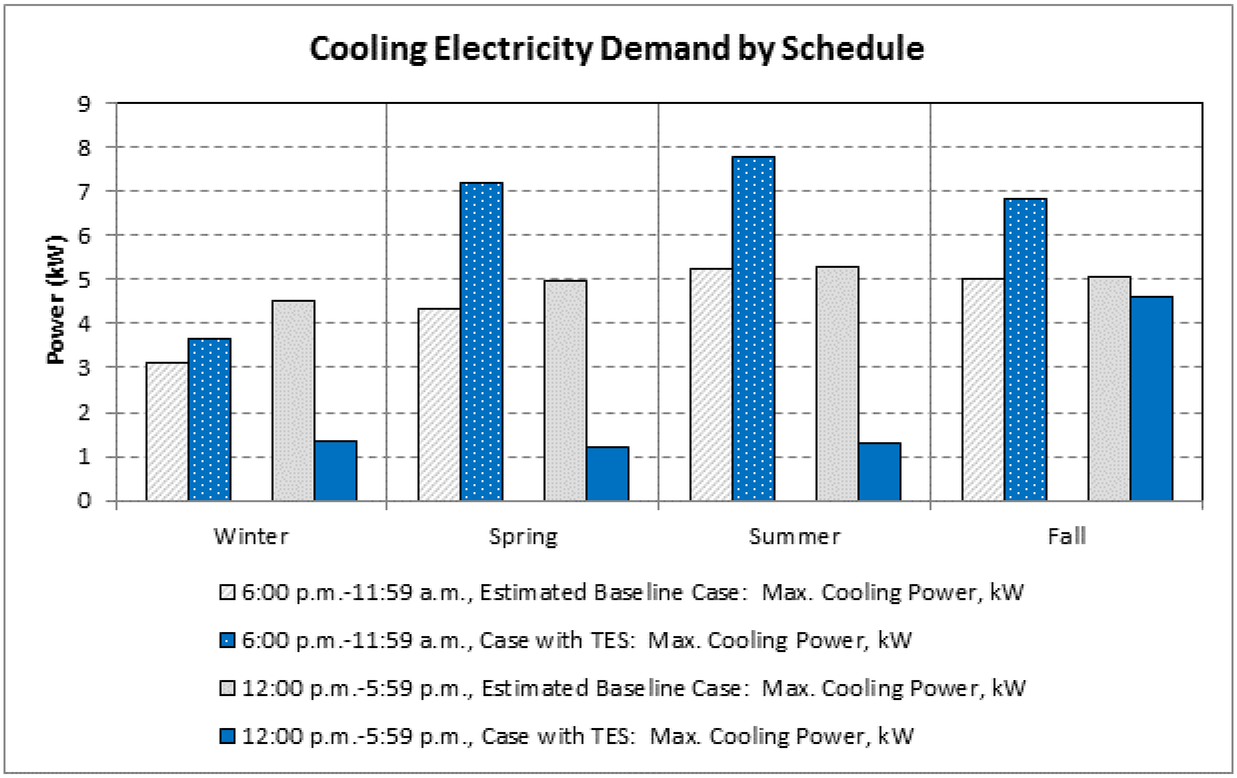

Figure 5-7 Cooling electricity demand by schedule for Site 2

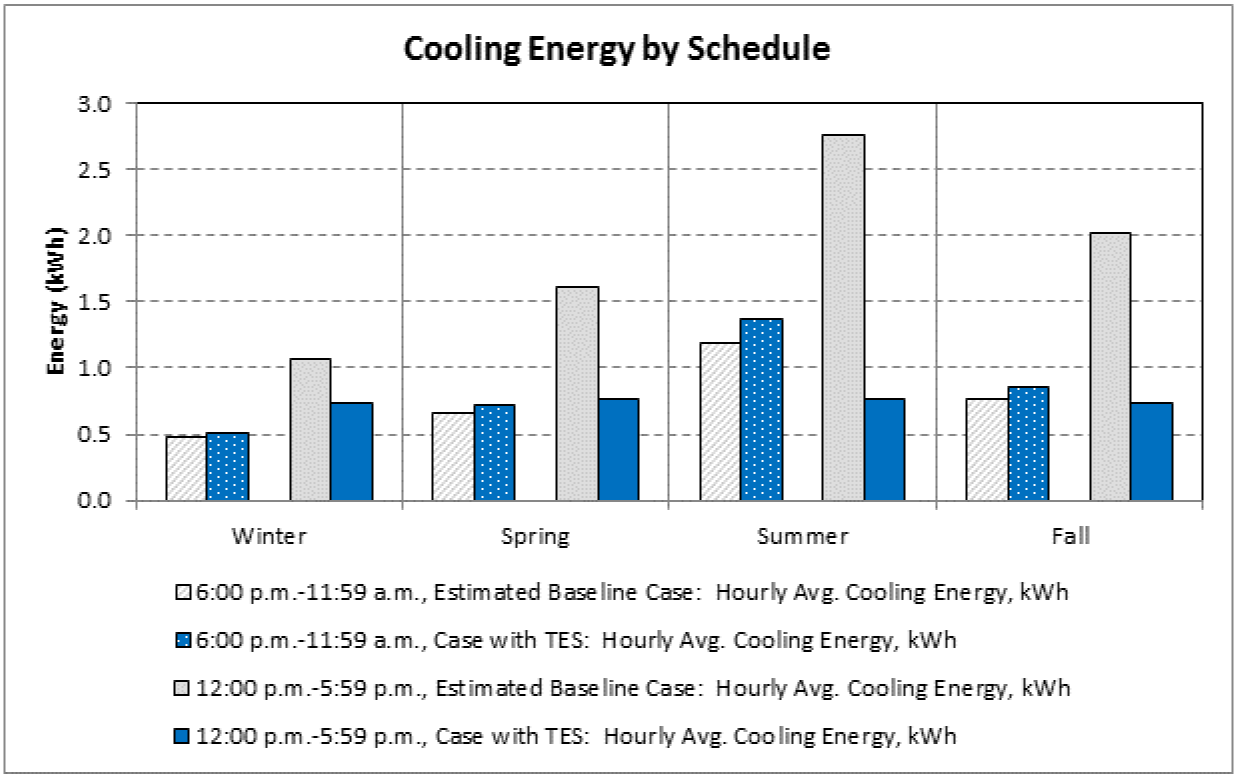

Figure 5-8 Cooling energy by schedule for Site 2

Table 5-6 Cooling Electricity Demand at Site 2

	6:00 p.m.-11:59 a.m.	12:00 p.m.-5:59 p.m.
Observed Case: Max. TES Power, kW	3.70	0.25
Observed Case: Max. DX Power, kW	5.24	4.58
Observed Case: Max. Cooling Power, kW	7.79	4.59
Estimated Baseline Case: Max. Cooling Power, kW	5.24	5.29

Table 5-7 Cooling Electricity Average Energy Consumption at Site 2

	6:00 p.m.-11:59 a.m.	12:00 p.m.-5:59 p.m.
Observed Case: Hourly Average TES Energy, kWh	0.50	0.07
Observed Case: Hourly Average DX Energy, kWh	0.42	0.68
Observed Case: Hourly Average Cooling Energy, kWh	0.92	0.75
Estimated Baseline Case: Hourly Average Cooling Energy, kWh	0.42	1.86

Table 5-8 Cooling Electricity Annual Energy Consumption at Site 2

	6:00 p.m.-11:59 a.m.	12:00 p.m.-5:59 p.m.	All Periods
Observed Case: Annual Cooling Energy, kWh	6,001	1,636	7,636
Estimated Baseline Case: Annual Cooling Energy, kWh	2,748	4,063	6,811

5.2 Site Performance Data from Project Partner 2

Electric Power Research Institute (EPRI) provided several months of data for TES systems that were tested at two Tennessee locations during EPRI projects in 2009 and 2010. The buildings were in different cities, but both are located within Climate Zone 4A as defined by DOE and ASHRAE. (Climate zones are described in more detail in Section 6.2.1.)

Table 5-9 Demonstration Sites 3 and 4

Case	Site 3	Site 4
State	Tennessee	Tennessee
Climate Zone	4A	4A
Facility Size	One story; 23,000 ft^2	One story; 14,700 ft^2
Facility Vintage	2009	1995
HVAC System Vintage	2009	2008
Total Installed HVAC Cooling Capacity	25 tons	20 tons
Capacity of Each DX Unit	5 tons	5 tons
Number and Location of DX Units	5 split systems; rooftop- and ground-mounted	5 packaged system units; ground-mounted
Space Type Served by TES Units	Commercial office addition	Laboratory and warehouse space
Number and Location of TES Units	One TES unit integrated with one DX split system	One TES unit integrated with one DX packaged unit
Monitoring Period for This Study	June 23, 2010 to September 27, 2010	July 20, 2009 to October 12, 2009

5.2.1 Site 3

At Site 3, the TES unit was scheduled to discharge and provide cooling between 10:00 a.m. and 9:00 p.m. An example day of performance data is shown in Figure 5-9. The figure starts at 10:00 a.m. in order to depict one complete discharging and charging cycle.

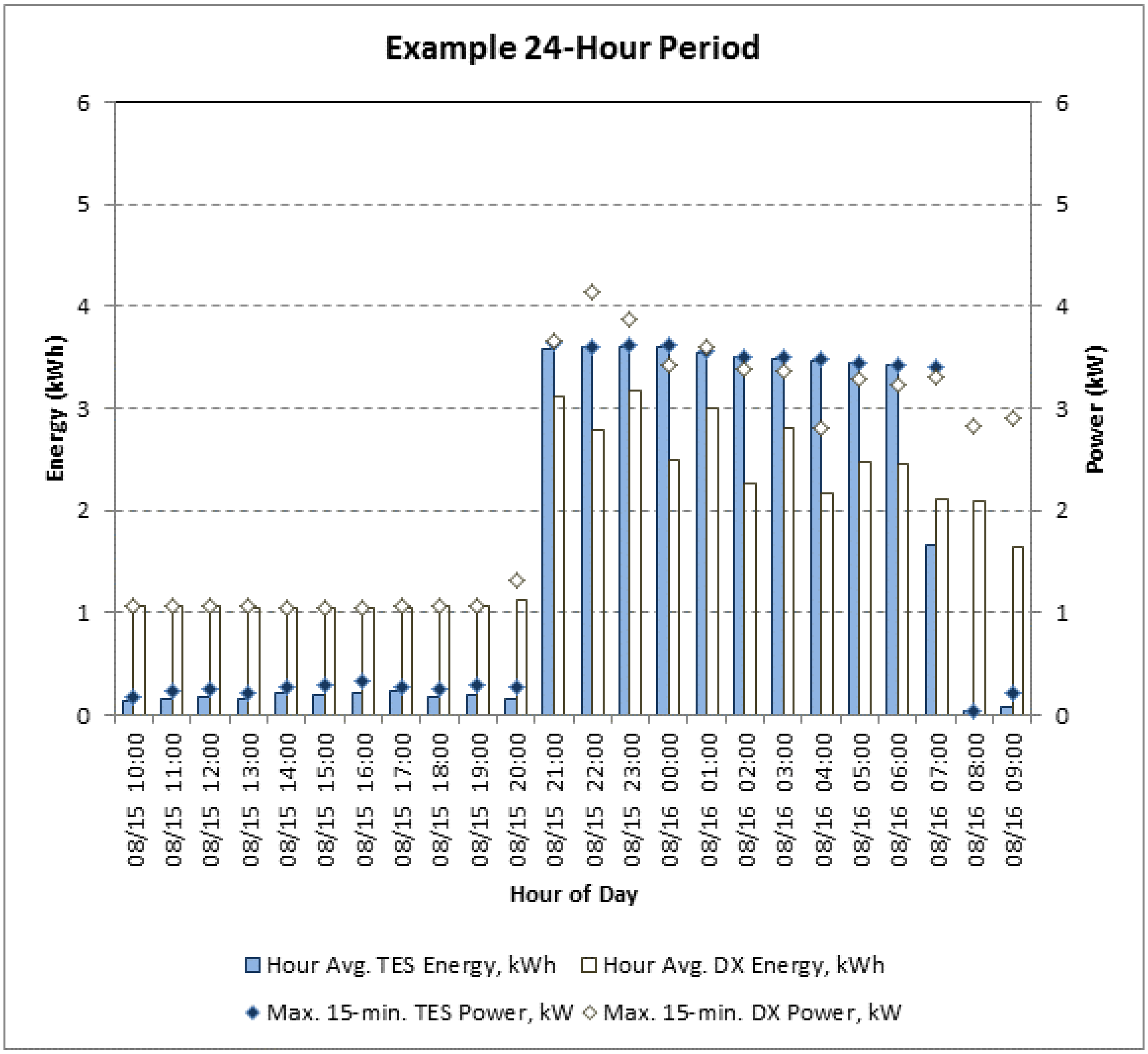

Figure 5-9 Example 24-hour period of performance data from Site 3

This site is part of a utility and does not have a time-of-use rate structure, so Figure 5-10 and Figure 5-11 summarize cooling electricity demand and energy consumption based on whether electricity was used within the TES discharge window (10:00 a.m. to 8:59 p.m.) or during other hours (9:00 p.m. to 9:59 a.m.). Key values are summarized in Table 5-10 through Table 5-12. For each month in the monitoring period, demand and energy were successfully shifted from the TES discharge window to other hours. The total cooling energy consumption, though, was estimated to be 13% higher for the case with TES than for the baseline case.

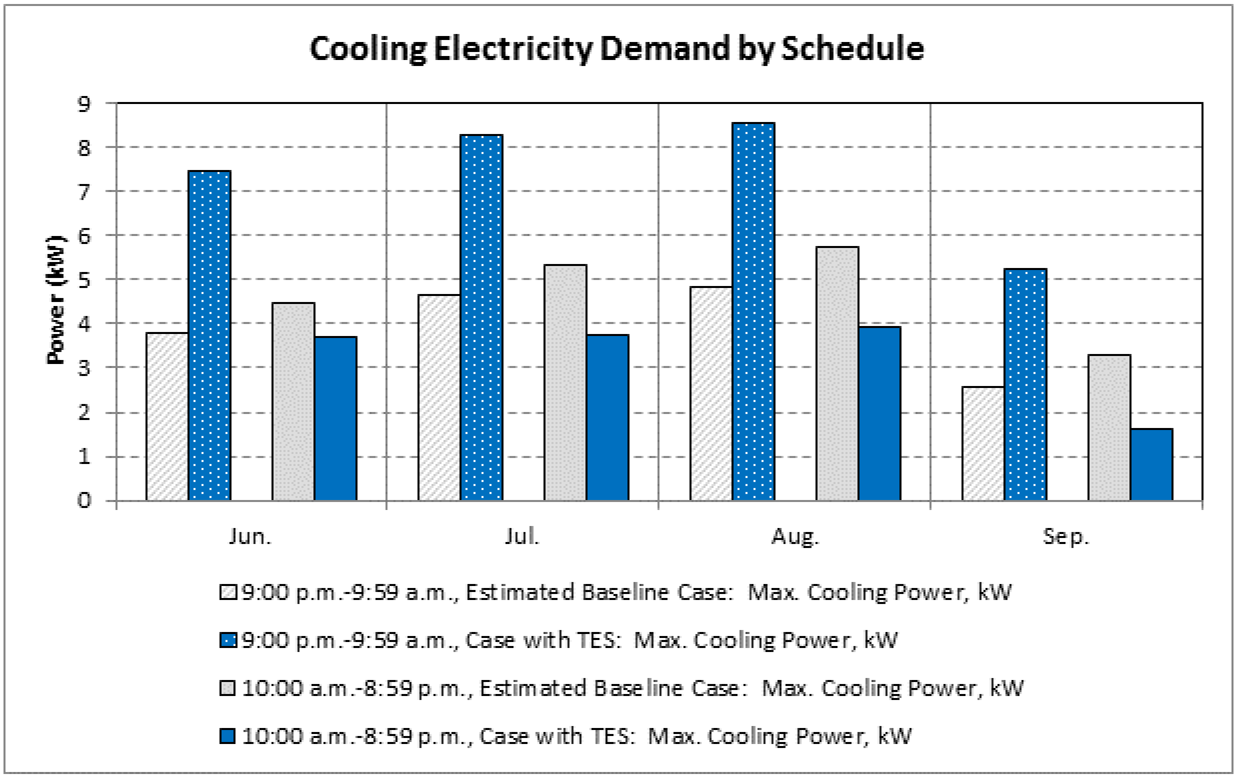

Figure 5-10 Cooling electricity demand by schedule for Site 3

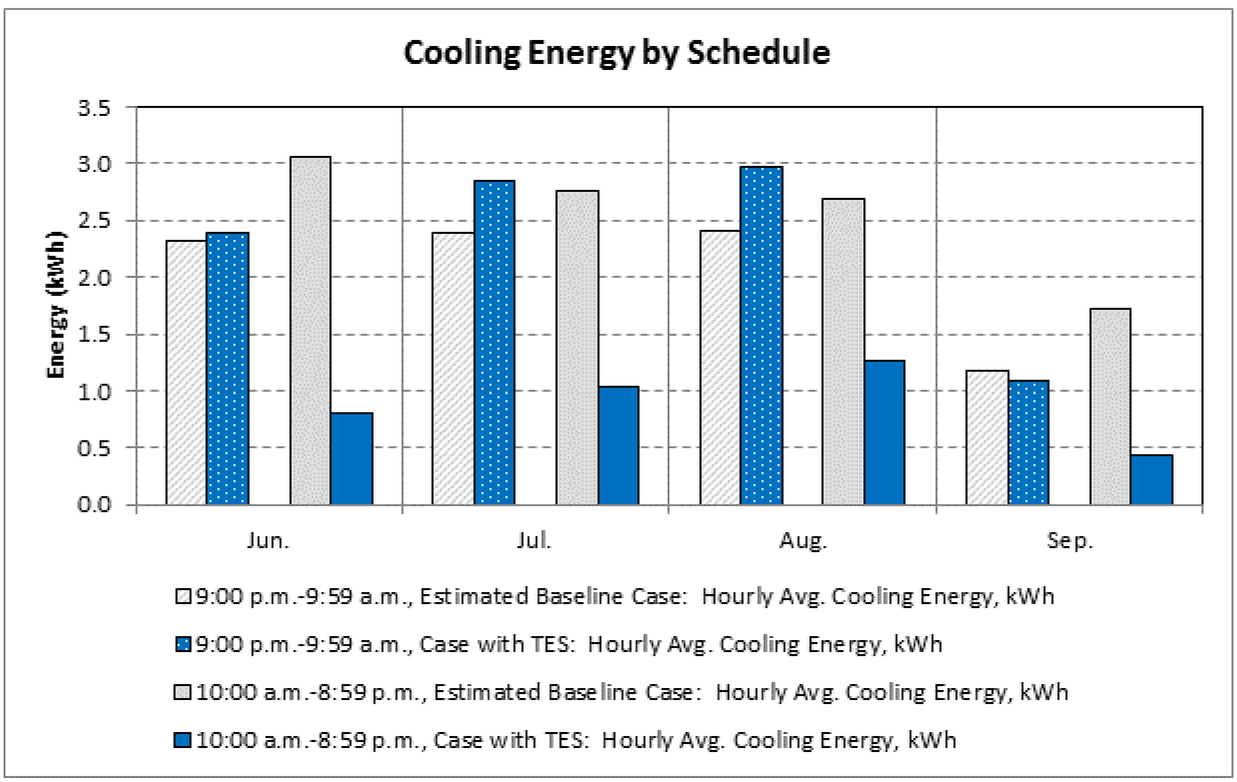

Figure 5-11 Cooling energy by schedule for Site 3

Table 5-10 Cooling Electricity Demand at Site 3

	9:00 p.m.-9:59 a.m.	10:00 a.m.-8:59 p.m.
Observed Case: Max. TES Power, kW	3.94	0.39
Observed Case: Max. DX Power, kW	4.84	3.83
Observed Case: Max. Cooling Power, kW	8.56	3.93
Estimated Baseline Case: Max. Cooling Power, kW	4.84	5.74

Table 5-11 Cooling Electricity Average Energy Consumption at Site 3

	9:00 p.m.-9:59 a.m.	10:00 a.m.-8:59 p.m.
Observed Case: Hourly Average TES Energy, kWh	1.90	0.18
Observed Case: Hourly Average DX Energy, kWh	1.67	0.70
Observed Case: Hourly Average Cooling Energy, kWh	3.56	0.88
Estimated Baseline Case: Hourly Average Cooling Energy, kWh	1.67	2.56

Table 5-12 Cooling Electricity Energy Consumption at Site 3 During Demonstration Period

	9:00 p.m.-9:59 a.m.	10:00 a.m.-8:59 p.m.	All Periods
Observed Case: Total Cooling Energy, kWh	4,384	957	5,340
Estimated Baseline Case: Total Cooling Energy, kWh	2,069	2,577	4,646

It was observed that during the final hour of the discharge window at Site 3 (8:00 p.m. to 8:59 p.m.), DX cooling was needed during about 6% of observed minutes. This is related to the fact that the discharge window at this site was longer than a typical application; ordinarily, the TES system used at this site is designed to provide 30 ton-hours of cooling for six hours if paired with a 5-ton DX system. As illustrated in Figure 5-12, the window of consistent peak demand reduction for this particular site and system design was 10:00 a.m. to 7:59 p.m. during the example month of July.

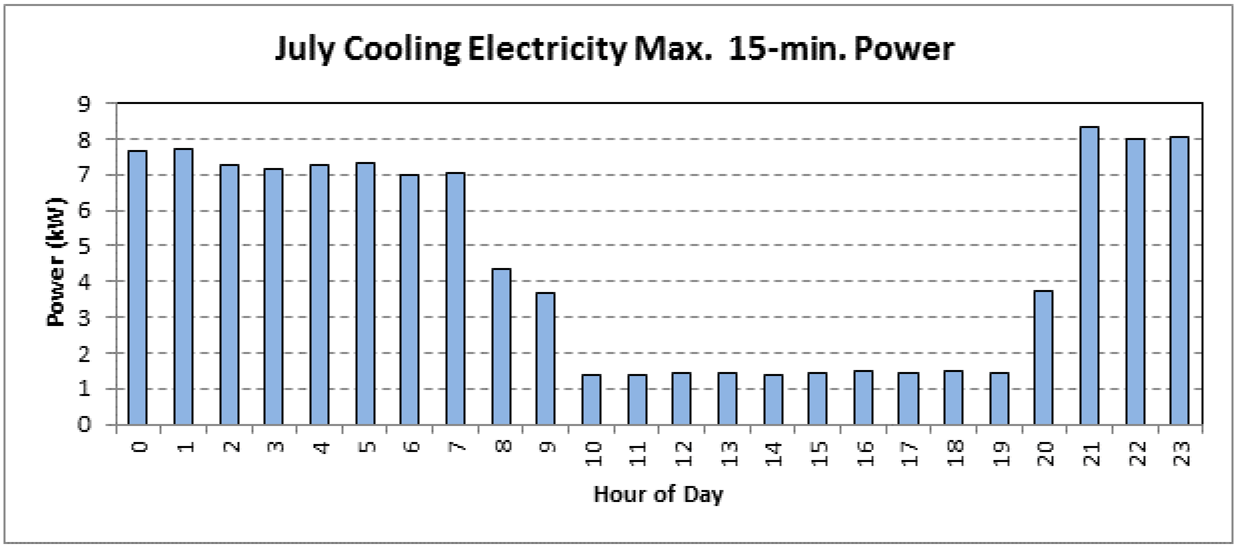

Figure 5-12 Site 3 cooling electricity demand by hour for an example month

Since Site 3 is part of a utility and does not pay conventional utility bills, the instances of DX cooling in the final hour of the discharge window are not problematic from a billing standpoint. At customer sites with time-of-use rate structures, however, TES scheduling can be optimized to ensure that DX cooling does not start within a peak period.

5.2.2 Site 4

At Site 4, the TES unit was scheduled to discharge and provide cooling between 12:00 p.m. and 8:00 p.m. An example day of performance data is shown in Figure 5-13. The figure starts at 12:00 p.m. (noon) so that it can depict a full discharging and charging cycle.

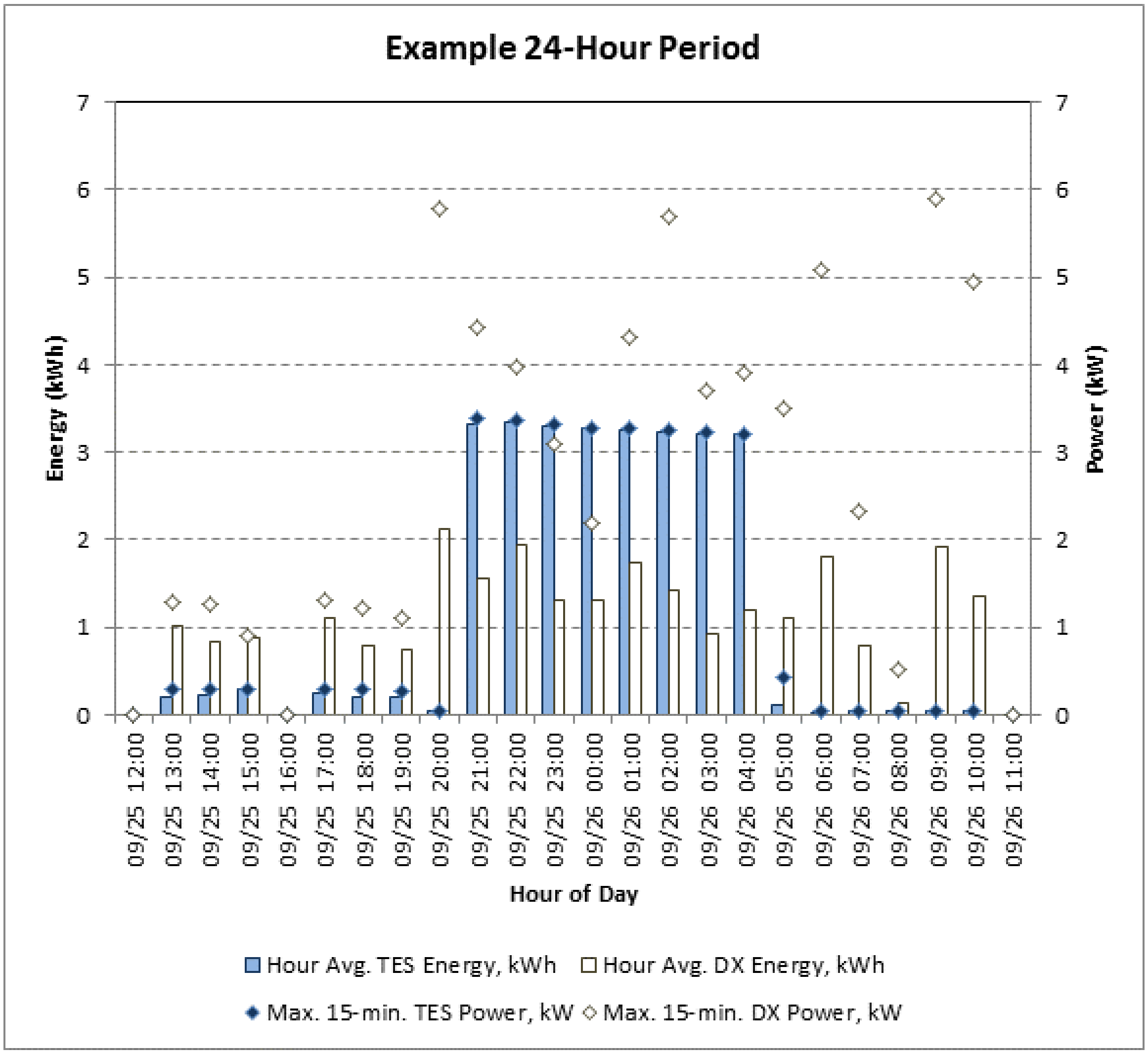

Figure 5-13 Example 24-hour period of performance data from Site 4

For the purposes of analyzing overall energy consumption and potential to reduce peak demand in a building setting, a subset of the monitoring period was selected during which cycling patterns of the TES and DX systems were relatively typical. This shorter period was selected to mitigate two issues. First, compared to the three other sites, Site 4 had a higher incidence of missing and erroneous data points that had to be removed (e.g., negative meter values); in Figure 5-13, for example, the hours of 12:00 p.m., 4:00 p.m., 11:00 a.m. are blank due to gaps in valid measurements. Second, for much of the remainder of the monitoring period, the TES system at Site 4 operated without cycling, which is different from how systems would be operated in a typical building setting.

The resulting subset was limited to September 18-28, which was the longest consecutive string of days with typical cycling patterns. Performance during this period is depicted in Figure 5-14 and Figure 5-15, with key values summarized in Table 5-13 through Table 5-15. During this period, demand is successfully shifted from the TES discharge window (12:00 p.m. to 8:00 p.m.) to other hours. This site does not have a time-of-use rate structure, so the figures summarize cooling electricity demand and energy consumption based on whether electricity was used within the TES discharge window. Additionally, total cooling energy during this period is about 6% lower than the estimated baseline cooling energy.

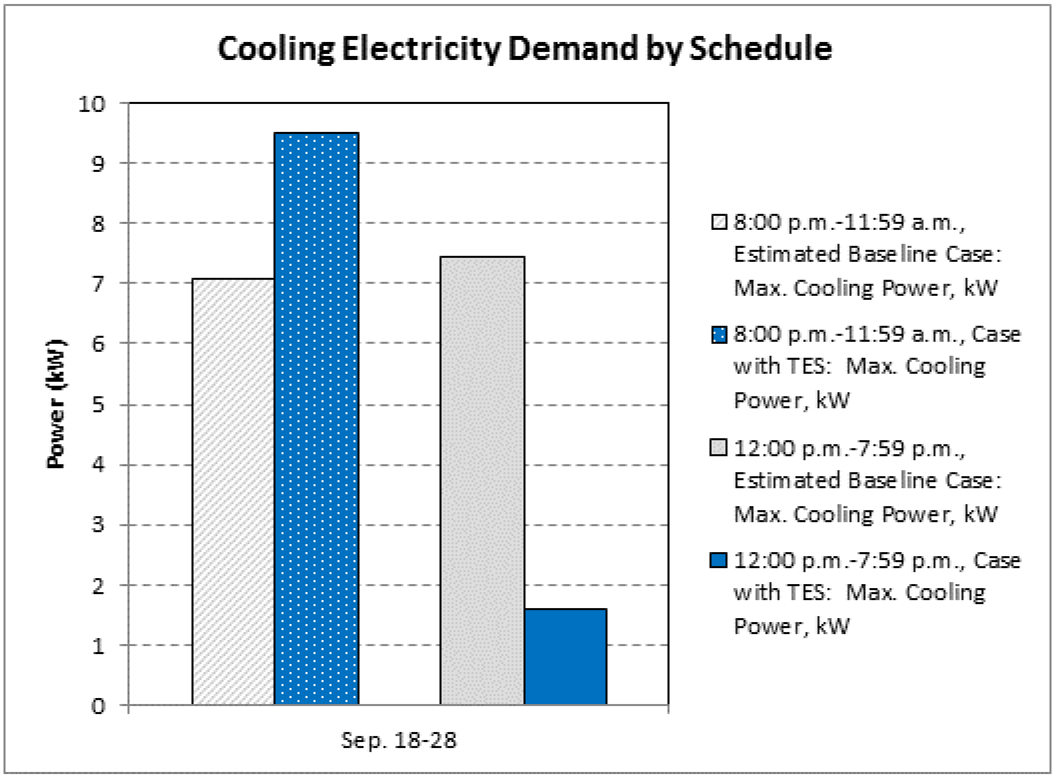

Figure 5-14 **Cooling electricity demand by schedule for Site 4**

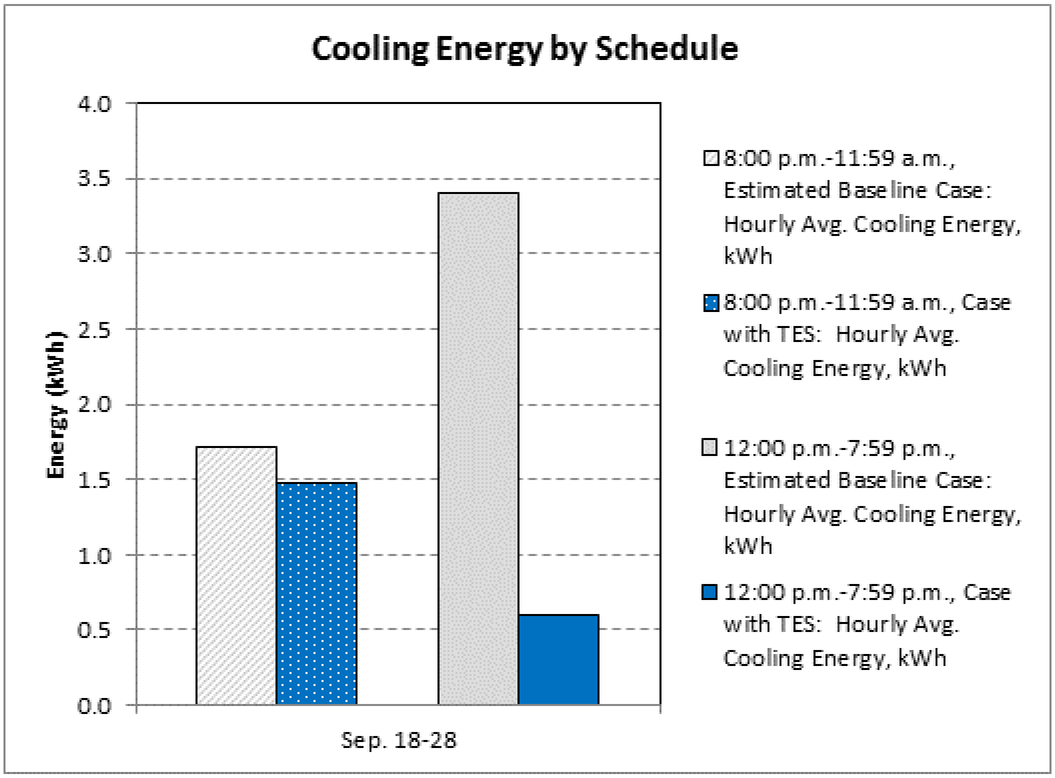

Figure 5-15 Cooling energy by schedule for Site 4

Table 5-13 Cooling Electricity Demand at Site 4

	8:00 p.m.-11:59 a.m.	12:00 p.m.-7:59 p.m.
Observed Case: Max. TES Power, kW	3.52	0.30
Observed Case: Max. DX Power, kW	7.09	1.31
Observed Case: Max. Cooling Power, kW	9.51	1.61
Estimated Baseline Case: Max. Cooling Power, kW	7.09	7.45

Table 5-14 Cooling Electricity Average Energy Consumption at Site 4

	8:00 p.m.-11:59 a.m.	12:00 p.m.-7:59 p.m.
Observed Case: Hourly Average TES Energy, kWh	1.03	0.14
Observed Case: Hourly Average DX Energy, kWh	0.89	0.47
Observed Case: Hourly Average Cooling Energy, kWh	1.91	0.60
Estimated Baseline Case: Hourly Average Cooling Energy, kWh	0.89	3.40

Table 5-15 **Cooling Electricity Energy Consumption at Site 4 During Demonstration Period**

	8:00 p.m.-11:59 a.m.	12:00 p.m.-7:59 p.m.	All Periods
Observed Case: Total Cooling Energy, kWh	266	36	301
Estimated Baseline Case: Total Cooling Energy, kWh	121	199	320

5.3 Comparison of Source Metrics

Published hourly location-specific conversion factors are available for calculating source emissions for the California demonstration sites, though insufficient public data are available for comparable source energy calculations at this time. In the case of source energy, some older loss rates distinguishing between peak, shoulder, and off-peak periods have been published (Wong 2011), but the scope is limited, and the vintage of the data (1990s in one case) suggests that the loss estimates may not be applicable to this analysis. Completion of high quality source energy calculations that account for differences in time of day will require future improvements in publically available data.

In the case of source emissions, however, data from prior research efforts were adequate to complete calculations. Using the OpenEI resource discussed in Section 3.2, hourly source emission factors for the CAMX eGRID subregion were selected. Hourly variations in emission factors result from differences in the mix of generator types operating in the CAMX eGRID subregion at different times of day and different times of the year.

To produce a second set of emissions estimates for comparison, the E3 tool described in Section 3.2 was also used. Hourly emission factors were averaged by hour of day and month; this step was taken to smooth out potentially non-replicable day-to-day variations in the original 8,760-hour modeled dataset, while preserving diurnal and seasonal patterns that would be expected to recur in future time periods.

For each site, baseline emissions were estimated by multiplying hourly energy consumption by hourly average emission factors for the applicable month and time of day. The emissions difference between the case with TES and the baseline case was then estimated by multiplying hourly energy consumption differences by hourly marginal emission factors. The resulting emissions differences and the percent change in emissions relative to the baseline are summarized in Figure 5-16, Figure 5-17, and Table 5-16.

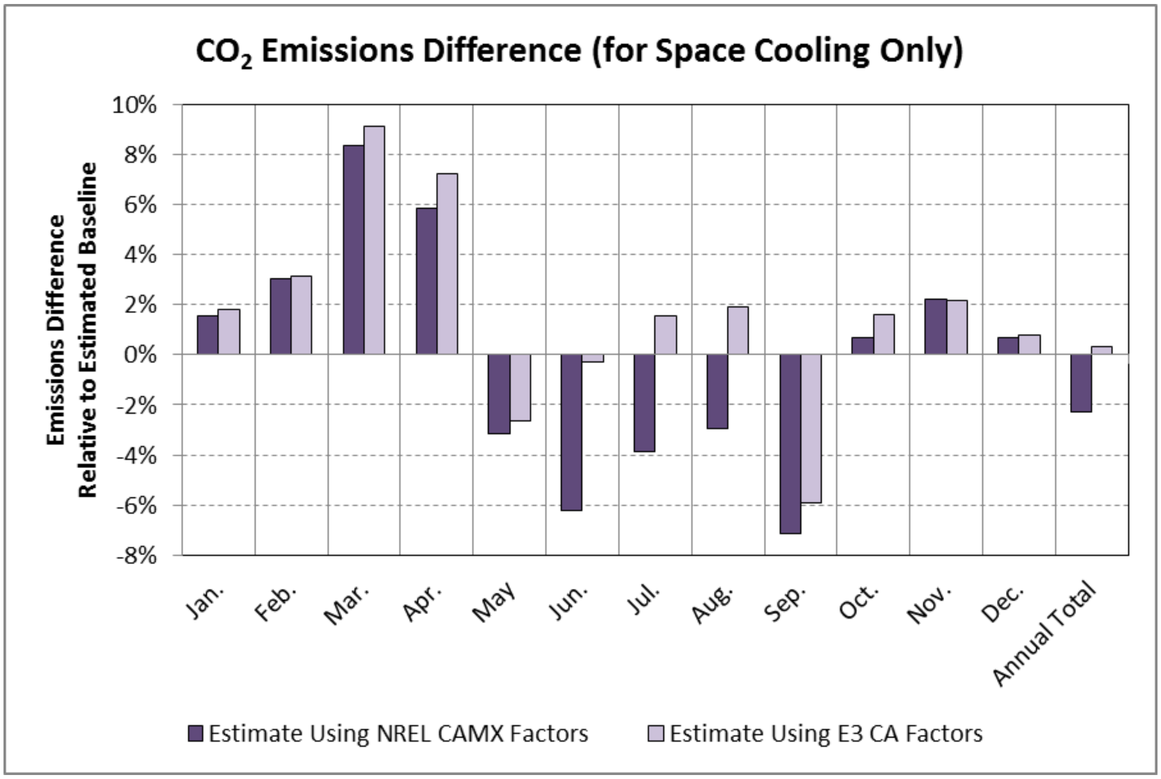

Figure 5-16 Estimated emissions comparison for Site 1

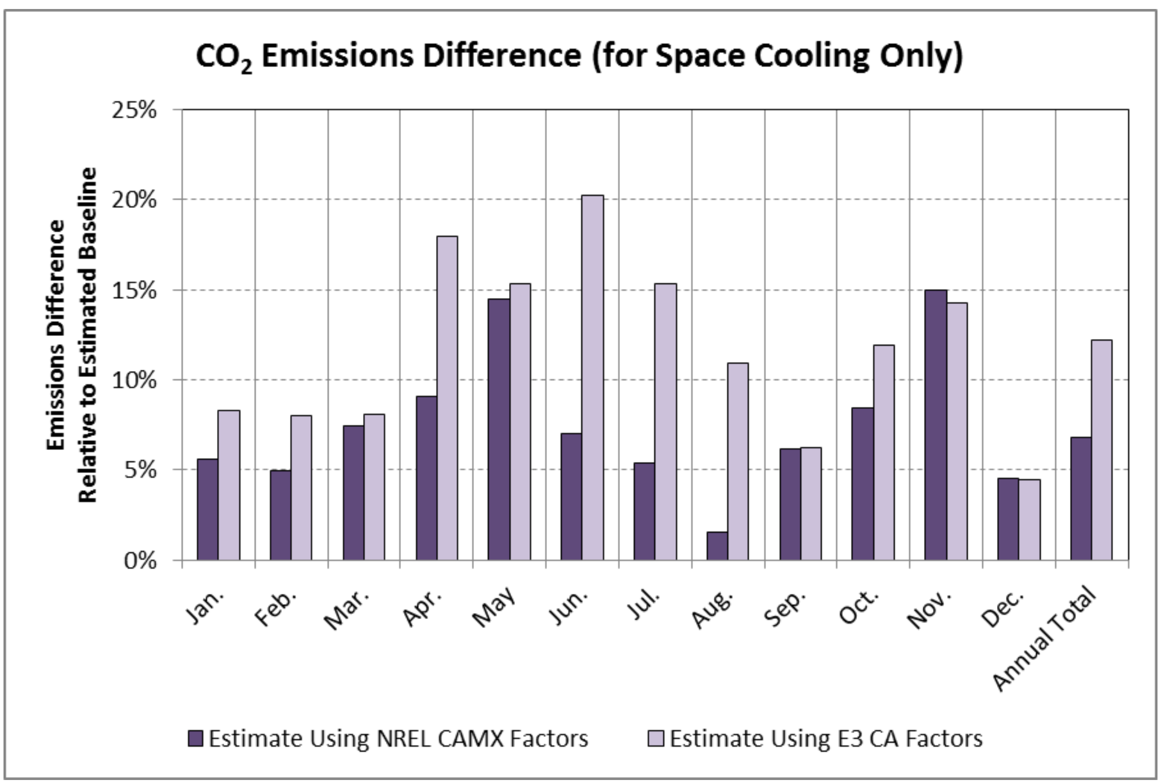

Figure 5-17 Estimated emissions comparison for Site 2

Table 5-16 Estimated Difference in Site Energy and Source Emissions for Cases with TES Relative to the Baseline Case

	Site 1	Site 2
Annual Site Energy Difference	+2.3%	+10.8%
Annual CO_2 Emissions Difference Using NREL Estimated CAMX Factors	-2.3%	+6.8%
Annual CO_2 Emissions Difference Using Adapted E3 CA Factors	+0.3%	+12.2%

The results reveal sensitivity of annual emissions to variations in the times of day when electricity is used. In particular, source metric trends can differ from site metric trends. The Site 1 calculation demonstrates that an increase in site energy can be accompanied by a decrease in source emissions of CO_2.

Additionally, even though the Site 1 and Site 2 calculations used the same hourly emission factors, the hourly differences in cooling load profiles between Sites 1 and 2 were sufficient to yield different emissions results. At Site 2, the increase in emissions is likely driven by an increase in site energy relative to the estimated baseline, which was large enough to overcome the region-specific emissions benefit of shifting load to off-peak hours.

These emissions estimates should be viewed as preliminary, rather than conclusive, because the emissions changes are small relative to the uncertainty in estimating baseline energy consumption and hourly emission factors. For example, if baseline energy consumption is underestimated, then the emissions difference for the case with TES will appear worse than it actually is; alternatively, if baseline energy consumption is overestimated, then the emissions difference for the case with TES will appear better than it actually is. The results demonstrate the importance of developing a strong understanding of case-specific load assumptions and cooling system characteristics when evaluating prospective adoption of TES systems.

An additional consideration is that both the NREL-estimated CAMX emission factors and the E3-estimated California emission factors reflect modeled snapshots of a particular year of grid operation. The basic methods illustrated here could be extended as a part of broader analyses that consider potential changes to the power system.

The results also suggest that emissions may be sensitive to alternative control strategies that could be tested in the future to respond to real-time pricing signals, generate additional utility benefits, or improve renewable energy integration.

6 Simulation-Based Analysis of a TES System

6.1 EnergyPlus Feature Addition

As part of this project, NREL produced an enhancement to the simulation platform EnergyPlus that enables users to model the performance of TES integrated with packaged AC units. EnergyPlus is a DOE-sponsored software application that is free to public users; it previously included two methods for modeling ice storage integrated with central plant chillers, but prior to this project, it did not include a method for modeling TES integrated with packaged AC (EnergyPlus 2012). The enhancement to accommodate additional TES systems will be available to the public with the release of EnergyPlus version 8.1 in the fall of 2013.

By adding the ability to model TES integrated with packaged AC to EnergyPlus, this project will potentially benefit the following types of technology evaluators in the commercial buildings community:

- Building design teams that use whole-building simulation will be able to better assess TES integrated with packaged AC as an option for comparison with other design alternatives.
- Engineers and analysts will be better able to evaluate and optimize solutions for integrating energy efficiency, energy storage, and renewable energy technologies.
- Guidance documents or simplified evaluation tools could be developed in the future for public use by combining the new simulation capability with methodologies in this report.

To represent a specific product, a user enters product-specific values as inputs to the model. These inputs include a wide range of performance characteristics, such as cooling capacities and coefficients of performance. The TES and DX units can be scheduled to operate in different modes of operation, including: DX cooling only; TES charging only; TES discharging only; simultaneous DX cooling and TES charging; simultaneous DX cooling and TES discharging; and off. The inputs also include performance curves that capture how power requirements vary with operating conditions. The ability to evaluate specific technologies depends on the availability of detailed system performance data that can be translated into performance curves or lookup tables used in an EnergyPlus model of the system. The new modeling capability is generic enough to represent a variety of technologies, including products available today and technologies that could be developed in the future to use different types of storage media or have specific performance characteristics.

6.2 High-Level Check of Model Behavior

As discussed in Section 2.4, field data can be used as a high-level check to see if a model is realistic given site-specific inputs that describe the facility, weather conditions, and key specifications of the evaluated technology, such as storage capacity, cooling capacity during discharge, electrical power input in different modes of operation, and charge and discharge times. As part of the testing of the new EnergyPlus feature, field data from the Site 1 demonstration location were combined with a DOE Reference Building Model to perform a high-level check for realistic outputs.

6.2.1 Whole-Building Energy Model Development Process

The starting point for the analysis was the DOE Small Office Commercial Reference Building Model for New Construction (Deru et al. 2011). The model for DOE Climate Zone 3B was selected because it includes Site 1. This model was adapted to incorporate known high-level characteristics of the Site 1 demonstration location, such as the building size and local weather data. Other details about system schedules, internal loads, building geometry, and building construction were not available for the demonstration site, so for these model elements, most attributes of the Commercial Reference Building Model were left unchanged.

Two models were produced for the purposes of the high-level check. The first model was a "baseline model" without TES. The second model was a model with TES.

The baseline model was produced by making the following modifications to the Commercial Reference Building Model:

- Location-specific values (latitude, longitude, time zone, elevation, design days, ground temperatures, and water mains temperatures) in the Commercial Reference Building Model were changed to values for a nearby city with published data on environmental conditions.
- The model was scaled down from 5,500 ft² to 3,300 ft² to match the size of the building from the Site 1 demonstration. The exterior façade lighting was manually scaled by the same ratio. A variety of other inputs such as interior lighting power and plug loads were defined in the Commercial Reference Building Model on a per area basis, so they automatically scale when a user changes the building size. The HVAC systems and service water heating (SWH) systems are "autosized" by EnergyPlus, so they also scale automatically with building size. The Commercial Building Reference Model is a five-zone model, so each zone was modeled with its own HVAC equipment autosized by EnergyPlus to meet the cooling capacity requirements of the zone. After reviewing initial results, a few internal loads, setpoints, and schedules were adjusted to reduce differences between modeled load profiles and high-level load profile patterns observed in data from Site 1.
- The HVAC control algorithm was modified to better reflect the algorithms of a typical rooftop unit based on work from a prior NREL project (Studer et al. 2012). This required changing the simulation time step in the model to one minute, and it involved the use of the optional Energy Management System (EMS) functionality in EnergyPlus to code and execute the more realistic RTU control algorithms. The HVAC fans were also modified to run continuously based on observations of the HVAC system at the Site 1 demonstration location.
- Measured ambient air temperature data from the Site 1 demonstration location were used as outdoor air temperature inputs for the modeled HVAC system. For other weather data inputs, measured 2012 weather data from a nearby airport weather station were procured and used in simulation runs.
- The model was modified to include HVAC systems capable of switching between DX units and TES units for cooling. For the baseline case, the TES system was turned off, and cooling loads were met with the DX units.

The model with TES was produced by making the following additional modifications:

- To represent the Ice Bear 30 product deployed at Site 1, NREL worked with technology developer Ice Energy Technologies to define appropriate performance curves and other product-specific inputs for use with the generic TES model object.
- The resulting cooling system with integrated DX and TES components was controlled as follows for the months of May through October:
    - Between 9:00 p.m. and 8:00 a.m., charge the TES storage tank (make ice) if it is not fully charged,[2] and use the DX system to meet any cooling loads.
    - Meet cooling loads between 8:00 a.m. and 12:00 p.m. with DX cooling only.
    - Meet cooling loads between 12:00 p.m. and 9:00 p.m. by discharging TES. (The system is sized to provide TES cooling until at least 6:00 p.m., but on some days, more TES cooling will be possible.) If TES charge is depleted before 9:00 p.m. and a cooling load remains, switch to DX cooling.
- For the remainder of the year, TES was not used, and cooling loads were met with DX cooling only.

6.2.2 TES Model Simulation Checks

Detailed data necessary for a calibrated model were not readily available for the demonstration projects in this report, and collection of such data was outside the scope of this project. Simulation feature testing is an iterative process, however, and future projects could be designed to further test the EnergyPlus feature using more detailed data and calibrated models. As an initial step, the analysis in this section shows that high-level trends in a modeled building with TES were comparable to that of an actual office building with the same technology, though differences in building details cause performance details to differ accordingly.

Figure 6-1 summarizes one month of cooling electricity demand and energy patterns for the simulation with the modified reference building model, combining results from all zones in the building. For comparison, Figure 6-2 depicts analysis results for Site 1 for the same month. Since measured data were provided for only half the cooling equipment at Site 1, measured values from Site 1 are doubled in Figure 6-2 to represent cooling electricity for the whole building. The cooling electricity values in both figures include power input to the DX and TES systems, excluding fan energy.

The two figures show that both buildings have similar diurnal cycles. Cooling electricity demand and energy consumption values are higher during off-peak hours, and TES discharge reduces demand between 12:00 p.m. and 9:00 p.m.

The magnitudes of the demand and energy values differ in a few respects between the two figures. The DX demand values are lower for the modified reference building model because the

[2] This is an illustrative example that is simpler than the charging logic used at Site 1, which adjusted charging start times based on state of charge and a target time for reaching full charge. The simplified approach was used for this analysis based on the level of data provided to NREL for this project, but more sophisticated controls can be implemented using the EMS feature in EnergyPlus.

combined cooling capacity of its autosized DX systems (7 tons) is smaller than the combined cooling capacity of the DX systems from the Site 1 demonstration (10 tons). The sizing difference is likely due to two factors:

- Differences in loads, construction, setpoints, and schedules between the two buildings contribute to differences in cooling loads. In the absence of detailed building data for calibration, system sizing differences are not unusual.
- The HVAC system at Site 1 may be oversized. Setpoint conditions were met in the modified reference building model, so the modeled system is not believed to be undersized. The hypothesis of an oversized system at Site 1 is supported by the ratio of maximum DX power to average DX energy observed in Figure 6-2: a high ratio suggests that the system cycles frequently, and the ratio for the system in Figure 6-2 is greater than that in Figure 6-1.

Another difference is that modeled cooling energy for the case with TES is greatest when charging starts (Hour 21) and then drops over the next few hours. One reason for this difference is that the modified reference building model uses a simple schedule control to start charging at 9:00 p.m. each night, whereas the system at Site 1 adjusts charging start times each day with a more complex algorithm based on state of charge.

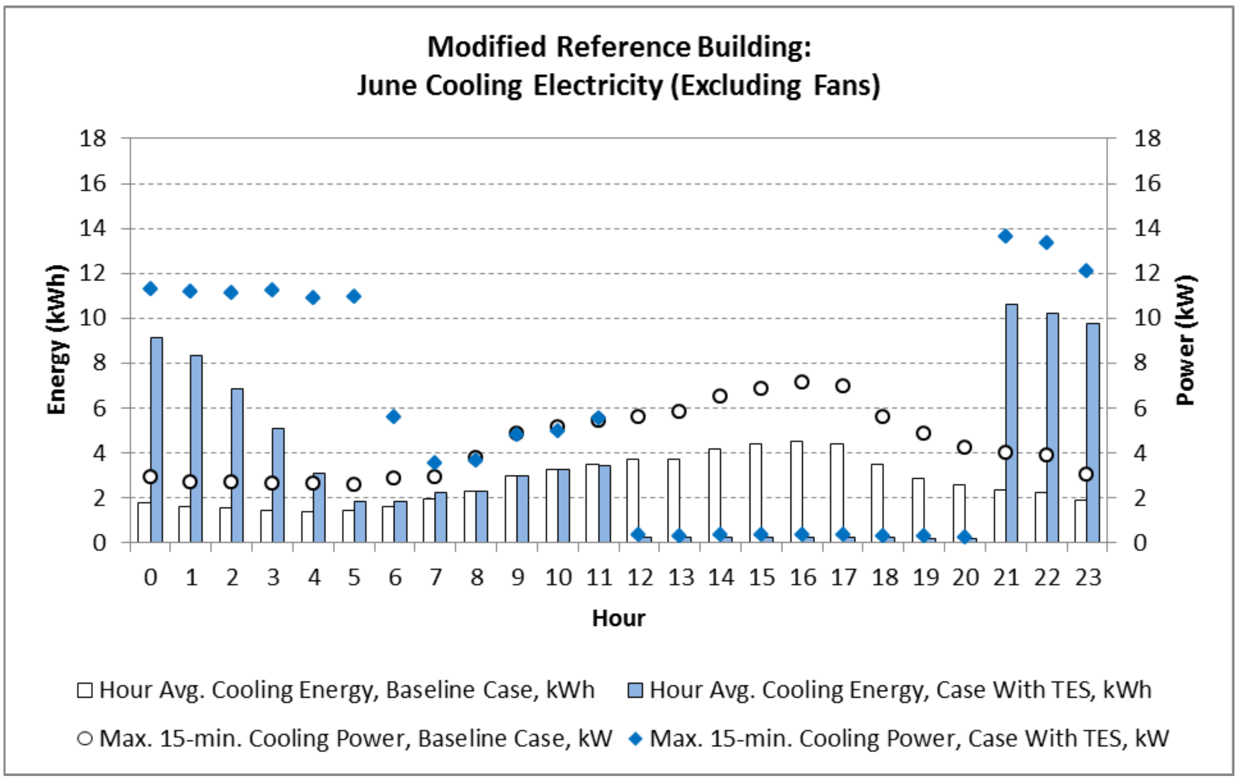

Figure 6-1 June simulation results for the modified reference building model

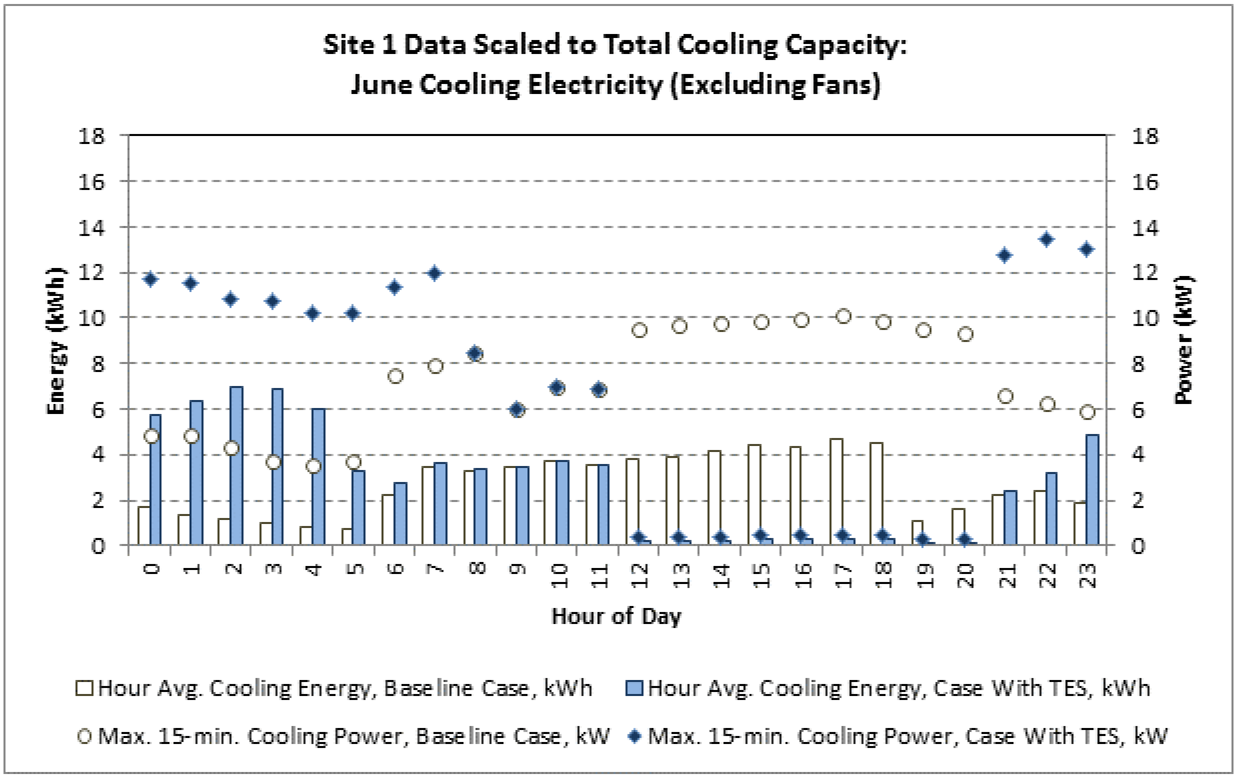

Figure 6-2 June Site 1 performance scaled to the building's total cooling capacity

These differences are reasonable given that the models used in this section are variations on the Commercial Reference Building Model, and they are not calibrated models of the actual building at Site 1. The model with TES shares a few qualities with the Site 1 demonstration building where possible—namely location, building footprint, and primary building activity. Many other details differ, including building construction, internal loads, HVAC equipment sizes, and system schedules. Given these differences, the outputs of simulations using the model with TES are not expected to closely match the data collected from the Site 1 demonstration, but the two buildings do share high-level trends in system behavior.

6.3 Extension to Nationwide Climate Zones and Additional Example Building Types

The next analysis demonstrates the ability of the new EnergyPlus TES model to facilitate comparisons of TES performance potential across climate zones and building types.

The inputs used in this simulation study were informed in part by performance characteristics of a particular TES product, but a significant number of additional modeling assumptions and simplifications were also necessary to address the following project limitations:

- Available field and laboratory testing data for the specified TES technology were limited compared to the data necessary for comprehensive model validation. The available data provided a beneficial starting point, and initial simulations conducted during this project were able to replicate high-level trends from demonstration data. Examples of future data that would be beneficial for further validation of the TES model include: greater detail about HVAC system controls and operation; improved baseline performance data; more

- information about building characteristics, loads, and whole-building performance; and TES performance data collected under a wider range of conditions and applications.
- Simplifications were necessary to rapidly generate a large number of models. The impact of these simplifications could be examined in future analyses and adjustments to inputs could be made accordingly. For example, autosizing capabilities in EnergyPlus were leveraged in this project, so future analyses could examine the sensitivity of modeled TES performance to system sizing differences.

The preliminary results of this simulation study illustrate how impacts can vary if a test combination of TES system characteristics and controls is replicated in different settings. Future analyses could incorporate additional data to refine model inputs and conduct further validation activities to more accurately reflect the potential impacts of a particular TES application.

6.3.1 Whole-Building Energy Model Development Process

The starting points for this analysis were the DOE Small Office, Stand-Alone Retail, and Strip Mall Commercial Reference Building Models for New Construction (Deru et al. 2011). These models represent examples of building types that often have packaged AC systems. For each of these three building types, a Commercial Reference Building Model is available for each of 16 U.S. climate subzones. Fifteen of these subzones were defined by dividing eight DOE climate zones into smaller regions based on whether they have “moist,” “dry,” or “marine” conditions; these 15 subzones are depicted in Figure 6-3 (DOE 2004). An additional subzone was defined for the coast of southern California, which is highly populated and differs from the rest of climate subzone 3B.

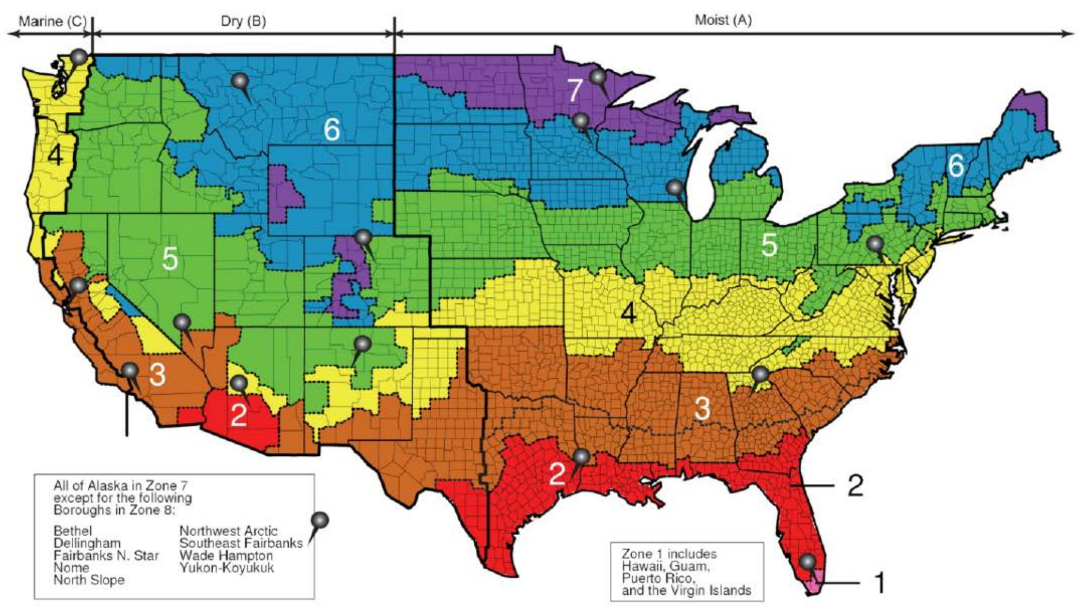

Figure 6-3 DOE climate zones (Credit: DOE 2004)

For each combination of location and building type, an applicable Commercial Reference Building Model was adapted as needed to produce two models: a baseline model without TES and a model with TES.

The process for developing these models followed the same general approach used in Section 6.2 with a few exceptions, including the following major differences:

- Weather data adjustments specific to the Site 1 demonstration were not used, because such adjustments are not applicable to this analysis. Instead, Typical Meteorological Year 2 (TMY2) weather data were used for each of 16 U.S. climate subzones to reflect the generalized nature of this analysis. The usage of TMY data here is for illustrative purposes only; alternative or additional weather data sets may be more appropriate for other studies, particularly those intended to capture the benefits of TES during extreme weather and load events. Considerations for selecting weather data sets are discussed in Section 2.4.
- Internal loads and HVAC setpoints from the original Commercial Reference Building Models were preserved.
- The standard method for representing DX cycling in EnergyPlus 8.0 was used in place of the custom approach used in Section 6.2.
- To produce baseline models for the stand-alone retail and strip mall building types, the unitary DX packaged systems from the corresponding Commercial Reference Building Models were adjusted to make them compatible with the new TES coil model.

For the purposes of this analysis, the same TES control logic from Section 6.2 was used in all test cases for consistency. (This approach is suitable for a generalized demonstration, but in site-specific simulation studies or analyses focusing on controls optimization, the control options tested should reflect the specific objectives of the study.)

6.3.2 Example Simulation Results for Site Metrics

For each location and building type, the analysis results show that the model with TES uses more annual site energy than the baseline model, but the timing of the energy consumption is consistently shifted into off-peak hours. These trends only reflect the implementations included in the example analysis; trends for other implementations may differ, and results will depend on case-specific details, including site conditions, building characteristics, TES and DX system performance details, and control logic.

Results for an example month are presented in Figure 6-4 through Figure 6-6, including all climate subzones used in the study.

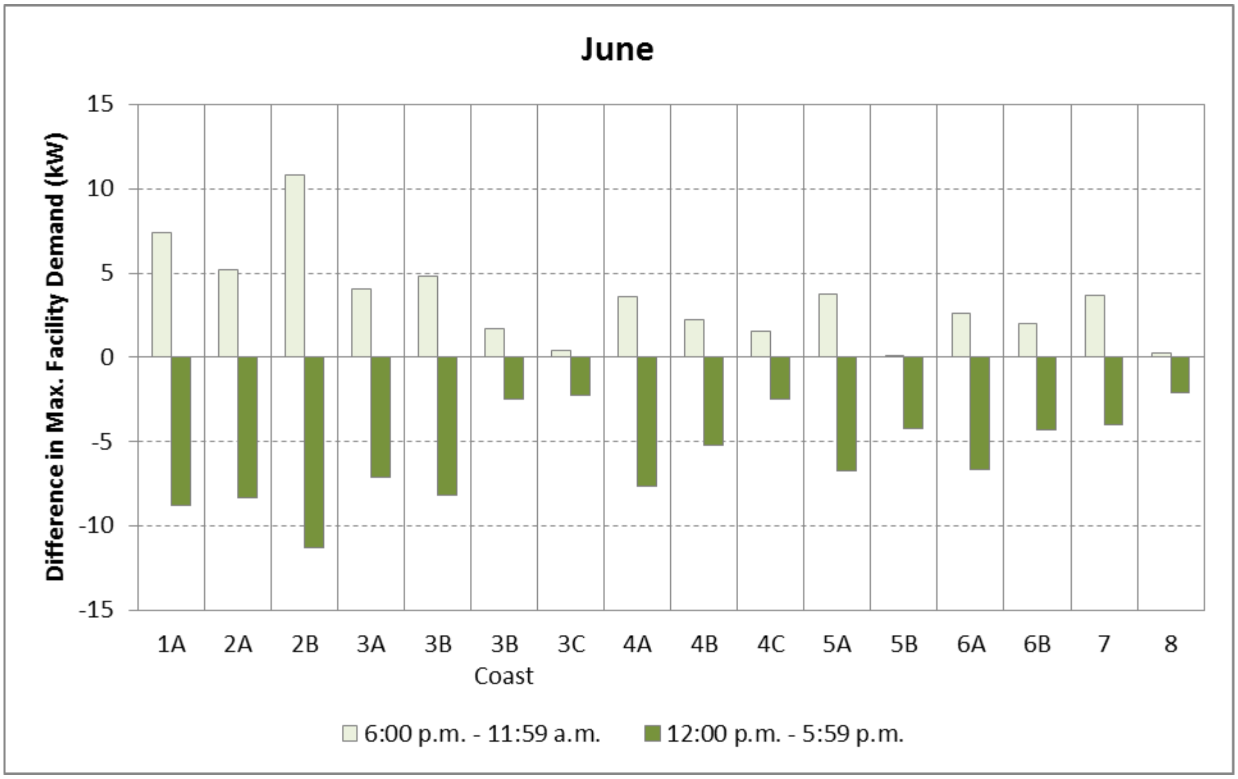

Figure 6-4 Small office model peak demand differences for an example month

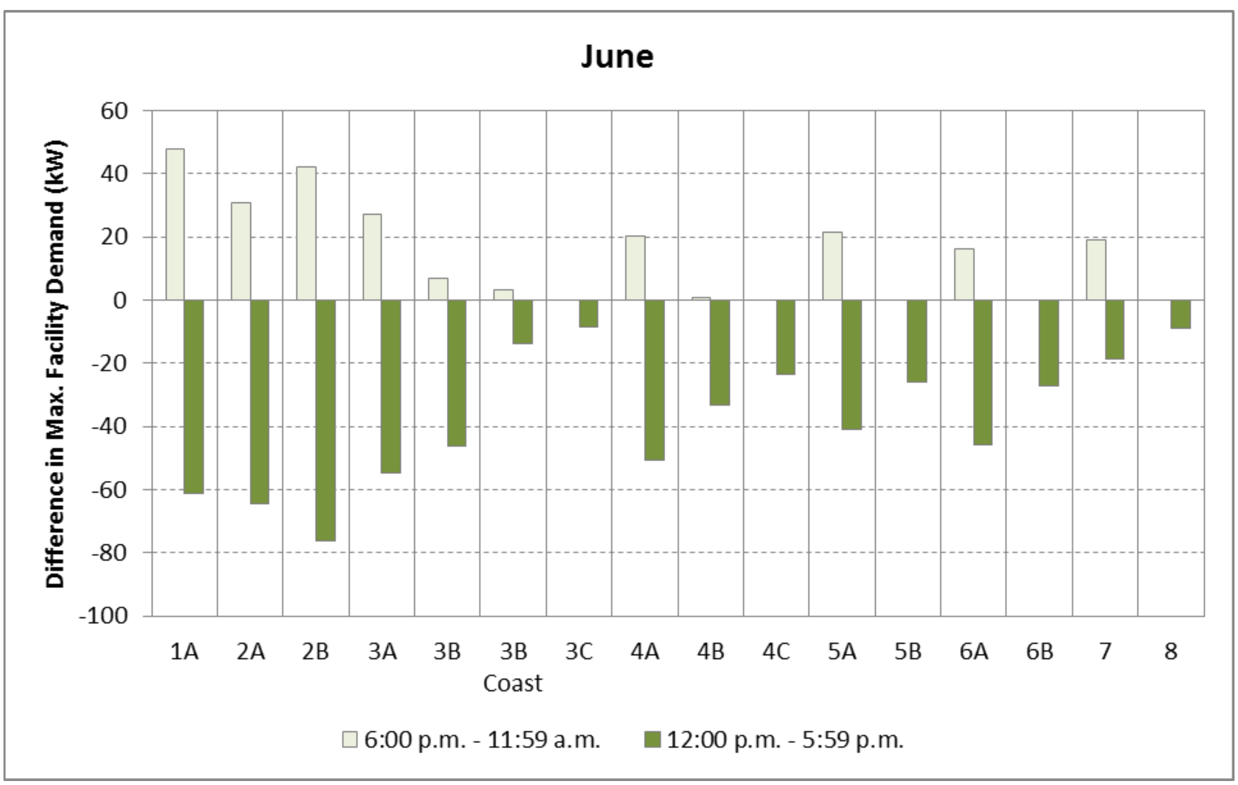

Figure 6-5 Stand-alone retail model peak demand differences for an example month

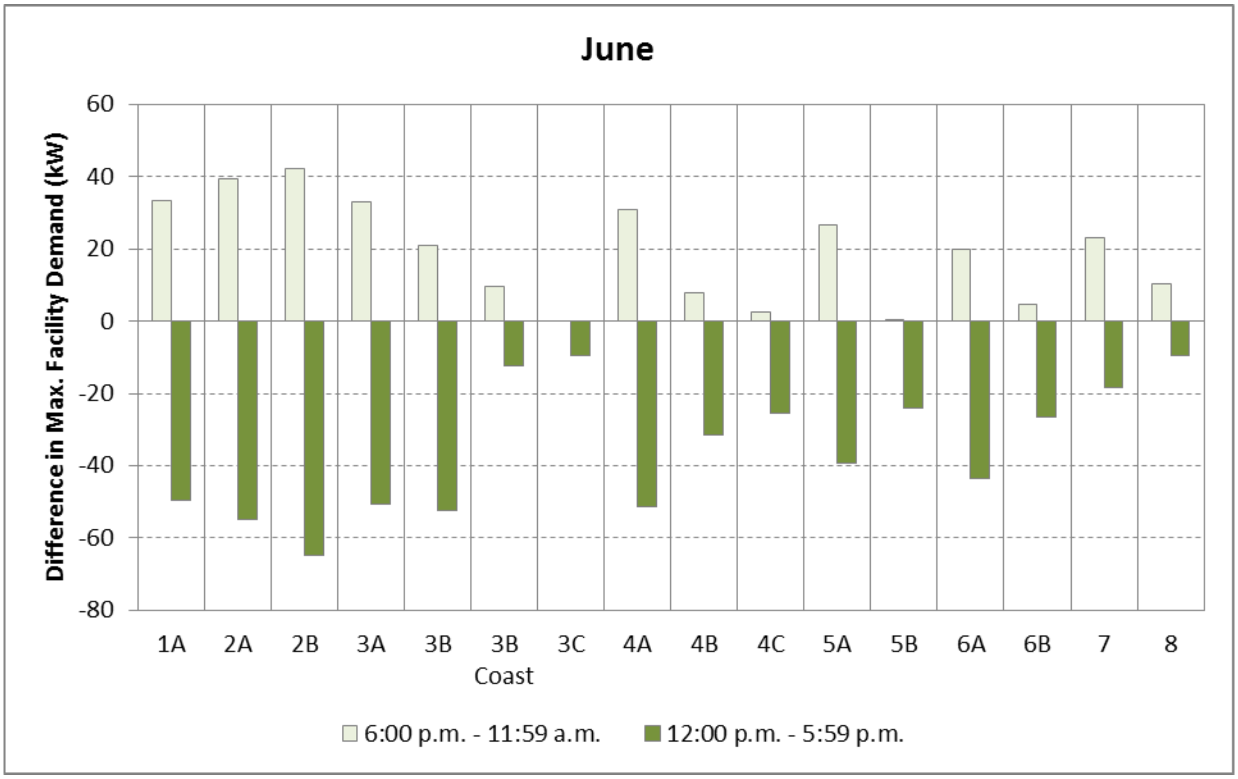

Figure 6-6 Strip mall model peak demand differences for an example month

A complete set of energy and monthly peak demand differences for each combination of building type and climate subzone is provided in Appendix C. Rate structures vary widely, and a tariff sensitivity analysis was outside the scope of this project, so cost impacts are not included in the appendix. A building owner's engineer can estimate cost impacts for a particular application by combining demand and energy performance results with the utility tariff specific to that site. A tariff sensitivity analysis could also be incorporated into future studies.

Across all climate subzones, the cases with TES successfully shift demand from on-peak hours to off-peak hours during summer months. The peak demand reduction tends to be smaller in cooler months, as would be expected for a TES technology integrated with a cooling system. The modeled cases with TES consume more overall energy than their baseline counterparts, but the cases with TES reduce energy consumption during peak hours as intended. Demonstration data also indicated that annual site energy increases are possible for some TES applications, and future analyses could examine contributing factors in more detail.

6.3.3 Future Data Required for Evaluating Source Energy and Emissions

The EnergyPlus enhancement has provided improved capabilities for evaluating site metrics, but site metrics alone are insufficient for evaluating the overall impacts of deploying building-sited TES. An important next step would be to translate site metrics into source metrics using source energy and emission factors that vary with time of day. If hourly factors are unavailable, an alternative would be to seek factors that at least vary between on-peak and off-peak hours. As noted in Section 5.3, adequate factors were unavailable for calculating source energy impacts for the demonstration sites, and this condition is common throughout the country. (One partial exception is discussed in Appendix A.) Similarly, marginal emission factors are not readily available at this time for most of the United States. Completion of quality site-to-source calculations that account for differences in time of day will require future improvements in data that are available to the public. Such efforts could be furthered through future collaborations with stakeholders involved in the generation, transmission, and distribution of power, as these parties may already be collecting some of the prerequisite data for other operational purposes.

7 Conclusions

This report presents an evaluation framework for engineers and analysts who assess technologies for building owners and utilities and are considering adoption of TES systems integrated with packaged AC. It provides methodologies for evaluating site demand and energy performance metrics and translating these values into source energy and emissions impacts. The framework does not provide methodologies for evaluating installation and maintenance requirements or conducting grid simulations, which are outside the scope of this report.

In addition to providing guiding concepts, the report applies multiple concepts from the evaluation framework to analyze performance data from example demonstration sites. These analyses show that TES systems can successfully shift electric demand and energy to off-peak hours in a variety of circumstances. Analyses of demonstration data also show that such strategies can come with site energy savings or increases, depending on site-specific conditions.

As part of this project, NREL produced an enhancement to the simulation platform EnergyPlus that enables users to model the building-level performance of TES integrated with packaged AC units. Expected benefits of this work include:

- Building design teams that use whole-building simulation will be able to better assess TES integrated with packaged AC as an option for comparison with other design alternatives, including other storage technologies.
- Engineers and analysts will be better able to evaluate and optimize solutions for integrating energy efficiency, energy storage, and renewable energy technologies.
- Guidance documents or simplified evaluation tools could be developed in the future for public use by combining the new simulation capability with methodologies in this report.

Site metrics alone are insufficient for evaluating the overall impacts of deploying building-sited TES, because such metrics do not capture dynamic interactions between building systems and the grid. An important next step is to translate site metrics into source metrics using source energy and emission factors that vary with time. To help with this step, this report includes guidance and considerations for evaluating source energy and emission factors at different timescales. Completion of quality site-to-source calculations with appropriate inputs at relevant timescales will require future improvements in data that are available to the public.

The example analyses in this report also indicate that emissions impacts are sensitive to hourly variations in load profiles. The results suggest that emissions and other source metrics may be sensitive to alternative control strategies that could be tested in the future to respond to real-time pricing signals, generate additional utility benefits, or improve renewable energy integration.

Realizing a broader range of TES benefits to utilities may require a combination of one or more of the following: reduction in technology costs, advancements in the design of electricity market products that capture the impacts of on-site energy storage, and collaboration between utilities and building owners. In particular, TES presents an opportunity to improve the integration of renewable energy systems, and multiple utility stakeholders have expressed interest in future efforts to advance the industry's understanding of how to realize this potential. Improved integration could be measured with a combination of metrics, including source energy reductions, fossil fuel reductions, emissions reductions, and cost-effectiveness. Demonstration projects to date have not attempted to integrate control approaches for TES, packaged AC, and renewable generation systems with the intent of improving grid impacts of highly efficient buildings that export renewable power. Future demonstration projects could be designed to quantify how the coordinated control of on-site generation, loads, and storage systems can optimize facility load profiles from a grid perspective.

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Appendix A Additional Considerations for Source Energy Calculations

This section provides an initial examination of example data that can help when assessing the significance or negligibility of regional and time-dependent variations in factors used in site-to-source energy calculations for energy storage measures. This section does not describe a detailed analysis of regional and time-dependent factors, which would be outside the scope of this project; rather, this section discusses examples to demonstrate an approach and identify considerations that can be applied to other case-specific data.

The following sections demonstrate an approach for translating site energy into source energy that can be applied when loss factors in the electric power system are available at different timescales.

A.1 Source Energy Factors

The general relationship between site and source energy can be defined as:

$$Source\ Energy = Site\ Energy \times SEF \tag{A-11}$$

Where:

SEF = source energy factor

The authors recommend defining source energy factor in a manner that accounts for losses during four stages of activity: distribution, transmission, generation, and precombustion. Distribution losses and transmission losses result from the delivery of electricity over wires and through equipment located between electricity generators and end users. Generation losses occur at power plants during the conversion of fuels into electricity. Precombustion losses occur during the "extraction, processing, and transportation" of fuels that are used in power plants (Deru et al. 2007).

Each of the four stages of activity can be characterized by its own loss factor, which contributes to the overall source energy factor:

$$SEF = \frac{1}{(1-DLF)(1-TLF)(1-GLF)(1-PLF)} \tag{A-12}$$

Where:

DLF = distribution loss factor

TLF = transmission loss factor

GLF = generation loss factor (at power plants)

PLF = precombustion loss factor

In this definition, each loss factor, LF, is dimensionless and takes the following general form[3]:

$$LF_{1,2} = \frac{Loss_{1,2}}{Input_1} \quad \text{(A-13)}$$

Where:

$LF_{1,2}$	=	loss factor from Point 1 to Point 2
$Loss_{1,2}$	=	power loss (kW) from Point 1 to Point 2
$Input_{1,2}$	=	power input (kW) into Point 1

For example:

$$DLF = \frac{Distribution\ System\ Losses}{Power\ Entering\ the\ Distribution\ System} \quad \text{(A-14)}$$

If loss-related values are easier to find in other formats, the source energy factor equation can be rearranged for convenience. For example, a report by Deru et al. (2007) references a generation efficiency assumption instead of a generation loss factor. It also quantifies "precombustion effects" for different regions in units of precombustion energy loss per unit of site energy. To accommodate these two data formats, the source energy factor definition can be rearranged as:

$$SEF = \frac{1}{(1-DLF)(1-TLF)\eta_G} + P \quad \text{(A-15)}$$

Such that:

$$Source\ Energy = Site\ Energy \times \left[\frac{1}{(1-DLF)(1-TLF)\eta_G} + P\right] \quad \text{(A-16)}$$

Where:

DLF	=	distribution loss factor
TLF	=	transmission loss factor
η_G	=	generation efficiency at power plants
P	=	precombustion energy loss per unit of site energy

[3] As a caution, the term "loss factor" is not standardized in the industry; some references may define loss factors to be ratios of different values, such as losses over usable output power. Before using loss factors from other references in the equations described here, check how each reference defines its loss factors, and adjust them as needed.

Marginal loss factors reflect the change in losses resulting from incremental changes in loads, so they are preferred over average loss factors when estimating source energy impacts for load management strategies, including deployment of energy storage. On the other hand, average loss factors are more readily accessible to the general public and may be used by stakeholders who lack access to marginal loss factors. When using average loss factors, it is important to understand potential sources of error.

Lazar and Baldwin (2011) suggest that when analysts account for line losses as part of evaluating energy efficiency measures, most analysts use average line loss factors because they are measured and published more often than marginal loss factors. The use of average line losses, however, underestimates the benefit of a load reduction measure. Marginal line loss factors are greater than average line loss factors, and this disparity is greater when loads are high (Lazar and Baldwin 2011).

Comparisons of marginal generation loss or efficiency would also be more effective than comparisons of average generation loss or efficiency. When loads are at their highest, hourly marginal generation losses would be expected to be greater than average generation losses, because highly inefficient generators are usually dispatched last. At other times, the error introduced by using average loss factors or efficiency values is more difficult to generalize, given that generation involves the dispatch of power plants that can vary dramatically in terms of fuel type and part-load performance curves.

It is recommended that utility engineers and analysts use marginal loss factors where possible, as these parties may be able to access necessary data within their organizations. On the other hand, a building owner's engineer may lack access to marginal loss factors and need to start with average loss factors. If initial work with average loss factors suggests that more detailed analysis is warranted at a particular timescale of interest, a building owner's engineer may wish to work with a partner utility to examine marginal loss factors at that timescale as a next step.

Utility and building stakeholders would benefit from future work that assesses the sensitivity of site-to-source calculations to region, timescale, and the replacement of average loss factors with marginal loss factors. In the near-term, the methods in this report can serve as a framework for conducting initial calculations and identifying information gaps.

A.2 Distribution Losses

In many regions of the United States, hourly estimates of transmission and distribution losses are not easily accessible to building owners' engineers. One regional exception is ERCOT, which publishes forecasted and "deemed actual" transmission and distribution loss factors on its website (ERCOT 2013a). The deemed actual loss factors are estimates calculated as a function of electric load in 15-minute intervals. ERCOT's calculations include coefficients that are adjusted based on season (winter, spring, summer, or fall) and whether the time of day is an on-peak versus off-peak period. Readers interested in more detail can find ERCOT's methodology described in the *ERCOT Nodal Protocols* (ERCOT 2010).

In this section, example loss factors from public ERCOT data are examined to assess whether time-of-day variations appear to be significant—thus warranting further investigation—or whether time-of day variations appear to be negligible for this case.

ERCOT provides distribution loss factors for multiple Transmission/Distribution Service Providers (TDSPs). Some TDSPs are responsible for multiple service delivery points that are assigned unique loss codes; for these TDSPs, each loss code can be associated with a different loss factor (though this is not always the case). Figure A-1 summarizes distribution loss factors for each TDSP and loss code, using deemed actual values from 2012 as a recent example year. In this figure, distribution loss factors have been averaged by time-of-day. Thus, the figure represents an “annual average” day divided into 15-minute intervals, and each 15-minute interval has a different annual average distribution loss factor.

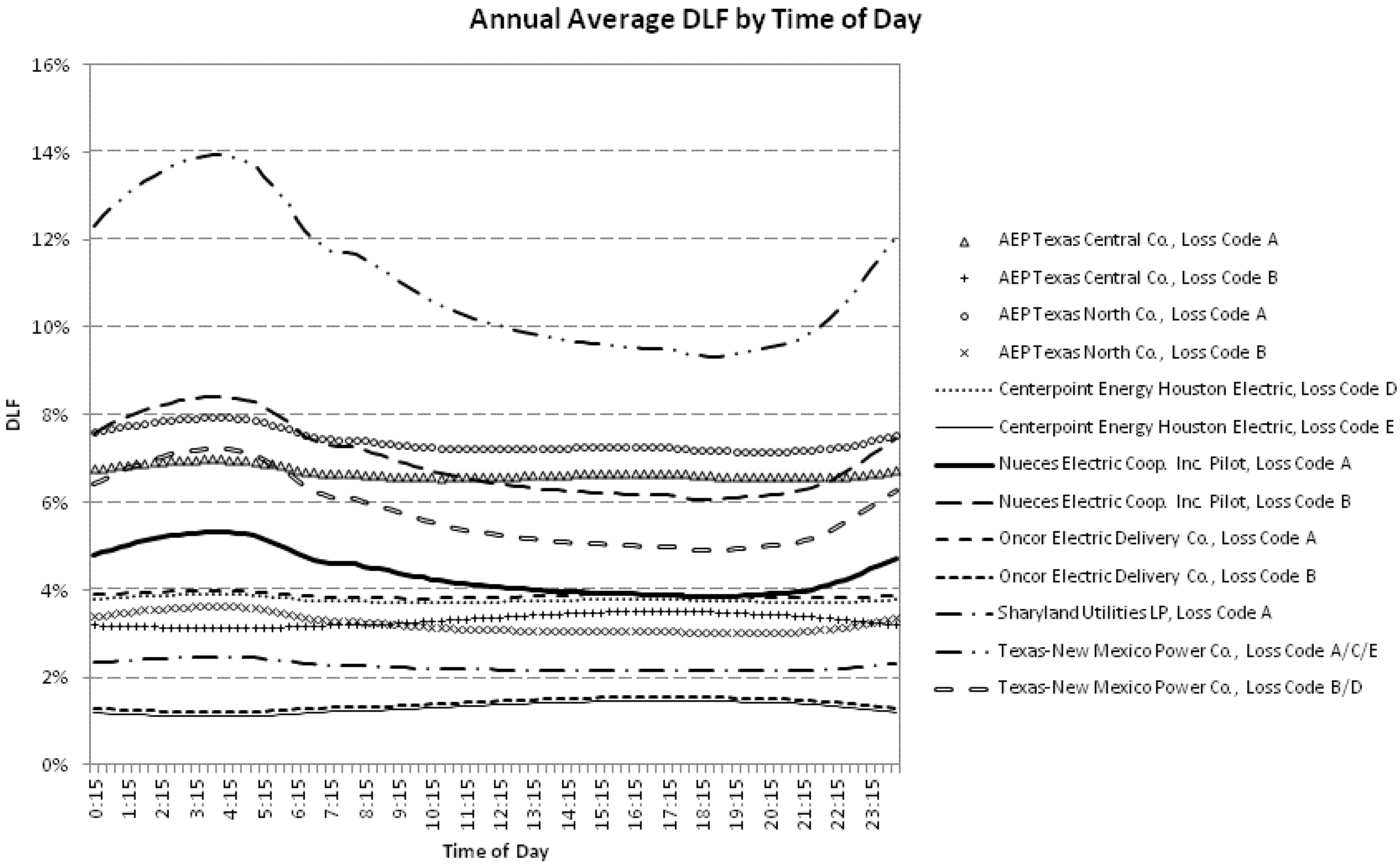

Figure A-1 **Annual average distribution loss factors by time of day for ERCOT TDSPs**

High-level observations about the data in Figure A-1 include:

- Distribution loss factors vary significantly between TDSPs. The average value for Texas-New Mexico Power Co. with Loss Codes A, C, and E (11.1%) is over eight times the average value for Centerpoint Energy Houston Electric with Loss Code E (1.3%).
- Distribution loss peaks do not necessarily align with periods of highest demand or highest transmission losses (see Section A.3). Most TDSPs in this example have average distribution loss factors that peak in early morning hours, though a few cases have peaks in the afternoon or early evening. If marginal loss factors were available and plotted instead of average loss factors, the marginal loss factor would be expected to more closely follow trends in load, with marginal losses peaking during peak load hours.
- Time-of-day variations are small for some TDSPs and large for others. The case with the greatest time-of-day variation is Texas-New Mexico Power Company with Loss Codes A, C, and E. (These three loss codes were assigned the same loss factors.) The case with the least time-of-day variation is Oncor Electric Delivery Company with Loss Code A. Table A-1 summarizes the variation in these two examples.

Table A-1 Variability in Annual Average Distribution Loss Factors for Two Cases

TDSP and Loss Code	Average DLF	Range Between Maximum and Minimum DLF	Range/Average	Standard Deviation
Oncor Electric Delivery Company with Loss Code A	3.9%	0.2%	4.5%	0.05%
Texas-New Mexico Power Company with Loss Codes A, C, and E	11.1%	4.6%	41.6%	1.57%

Further analysis by season reveals additional patterns that are not captured by annual averages. As an example, Figure A-2 summarizes season average[4] distribution loss factors by time of day for one TDSP and loss code: Nueces Electric Cooperative with Loss Code A. This case had annual values towards the middle of the range displayed in Figure A-1, and it was also one of the cases for which distribution losses appeared to vary significantly with time of day.

[4] Figure A-2 uses the same season boundaries as those used in the ERCOT methodology for calculating loss factors, with December through February assigned to winter, March through May assigned to spring, June through August assigned to summer, and September through November assigned to fall.

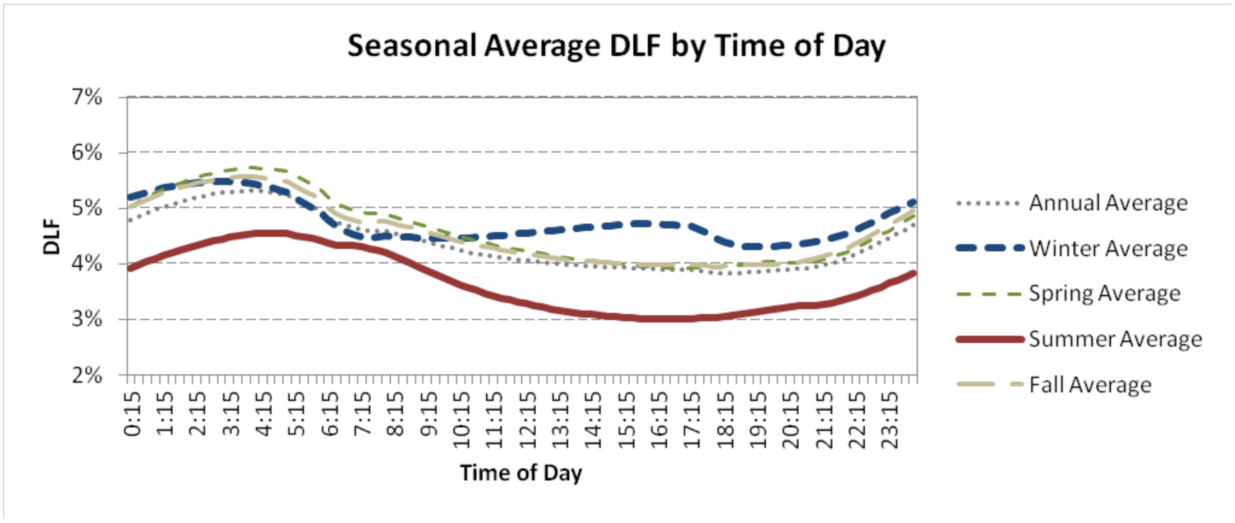

Figure A-2 Seasonal average distribution loss factors by time of day for Nueces Electric Cooperative with Loss Code A

Figure A-2 shows that in this particular case:

- Winter distribution loss factors are higher than summer distribution loss factors.
- All seasons show a daily peak for distribution loss factor in early morning hours.
- The winter profile also shows a smaller, secondary peak in the early afternoon.

Seasonal average distribution loss factors for this case are summarized in Table A-2.

Table A-2 Variability in Seasonal Average Distribution Loss Factors for Nueces Electric Cooperative with Loss Code A

Season	Average DLF	Range Between Maximum and Minimum DLF	Range/Average	Standard Deviation
Winter	4.8%	1.2%	25%	0.38%
Spring	4.6%	1.8%	40%	0.63%
Summer	3.7%	1.5%	42%	0.56%
Fall	4.6%	1.6%	36%	0.57%

Engineers assisting building owners within the ERCOT interconnection can use Figure A-1 to judge whether they want to neglect or further investigate time-of-day or seasonal variations in distribution losses.

At a minimum, the ERCOT data suggest that there would be value in improving the understanding of local and regional variations in distribution losses and providing supporting data in a simplified form accessible to building owners' engineers without sophisticated grid analysis software.

At this time, data such as those from ERCOT are not readily available to building owners' engineers in most other parts of the United States. Building owners' engineers without adequate data will have to either neglect time-of-day variations in distribution loss factors or request supporting data from partner utilities. Additionally, marginal distribution loss factors are difficult to find in all regions, and the replacement of average loss factors with marginal loss factors may require collaboration with utilities as well.

A.3 Transmission Losses

ERCOT also provides data on ERCOT-wide transmission losses. Figure A-3 summarizes seasonal average transmission loss factors by time of day. The averages are based on 2012 deemed actual values from ERCOT's website archive (ERCOT 2013a). Unlike its distribution loss factors, which peak in early morning hours for most TDSPs, ERCOT's transmission loss factors peak in late afternoon or early evening hours during spring, summer, and fall. The winter transmission loss factors differ in that they peak once in the early morning and again in the early evening.

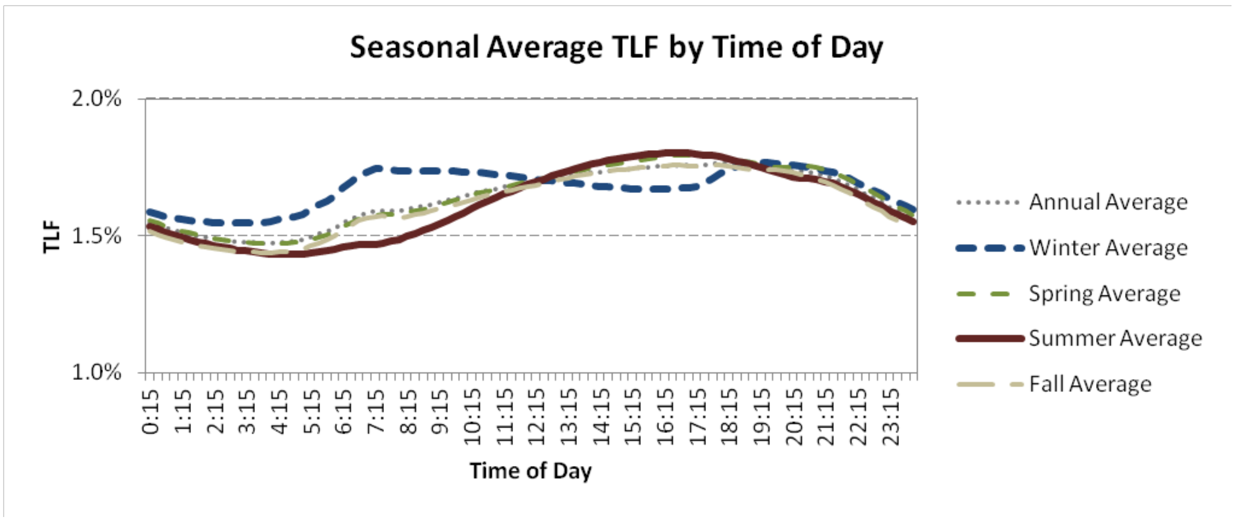

Figure A-3 Seasonal average ERCOT transmission load factors by time of day

Within any given season, the difference between the maximum and minimum transmission loss factor is significant relative to the average transmission loss factor—the range divided by the average is greater than 10% in each case. The absolute difference, however, is small relative to the overall site-to-source calculation. The low absolute variability for this loss factor is summarized in Table A-3, which shows that the range between the maximum and minimum value for each season is less than 0.5%.

Table A-3 Variability in Seasonal Average ERCOT Transmission Loss Factors

Season	Average TLF	Range Between Maximum and Minimum TLF	Range/Average	Standard Deviation
Winter	1.7%	0.2%	13%	0.07%
Spring	1.6%	0.3%	20%	0.11%
Summer	1.6%	0.4%	23%	0.13%
Fall	1.6%	0.3%	20%	0.11%

In this example, a building owner's engineer within ERCOT boundaries could assume a consistent transmission loss factor of about 2% throughout the day and throughout the year. Future analyses may be improved with better access to marginal transmission loss factors that could replace average transmission loss factors in such calculations.

A.4 Generation Plant Efficiency

As with transmission and distribution loss factors, generation plant efficiency can vary with time. An early question for a building owner's engineer with limited access to utility data is whether generation plant efficiency variations are significant or negligible when evaluating energy storage. This section describes a simplified approach for estimating time-of-day variation in generation plant efficiency.

The U.S. Environmental Protection Agency (EPA) publishes emissions, load, and heat input data from plants that must report emissions data to its Clean Air Markets program. Monitoring and reporting requirements and calculation methodologies are available through the EPA Clean Air Markets website (EPA 2012b). Public users can search for and download reported data through the online Air Markets Program Data (AMPD) tool (EPA 2013).

Example data were selected from the AMPD tool to produce an example calculation of hourly generation plant efficiencies aggregated at the state level. To identify a manageable sample of hourly data to download, a single month and state were selected for initial examination:

- August 2011 was selected as an example of a month in the cooling season.[5]
- Texas was selected for this example since it was also used in Sections A.2 and A.3, but this process could be repeated for other locations.

The downloaded data included hourly values for gross load, steam load, and heat input for Texas monitoring locations covered by EPA emissions reporting programs.[6] The collective efficiency of the electricity-generating plants was assumed to be the aggregated gross load divided by the aggregated heat input. Since the focus here is on impacts on the electricity grid, the calculation excluded steam-generating plants (about 1% of the downloaded data points). To reduce the risk of methodological inconsistencies between monitoring locations, the calculation also excluded monitoring locations that were not identified by AMPD as being assigned to a specific emissions reporting program (also about 1% of the downloaded data points). The gross load and heat input of the remaining locations were aggregated at the state level for each hour of the day. Hourly average efficiency values are summarized in Figure A-4.

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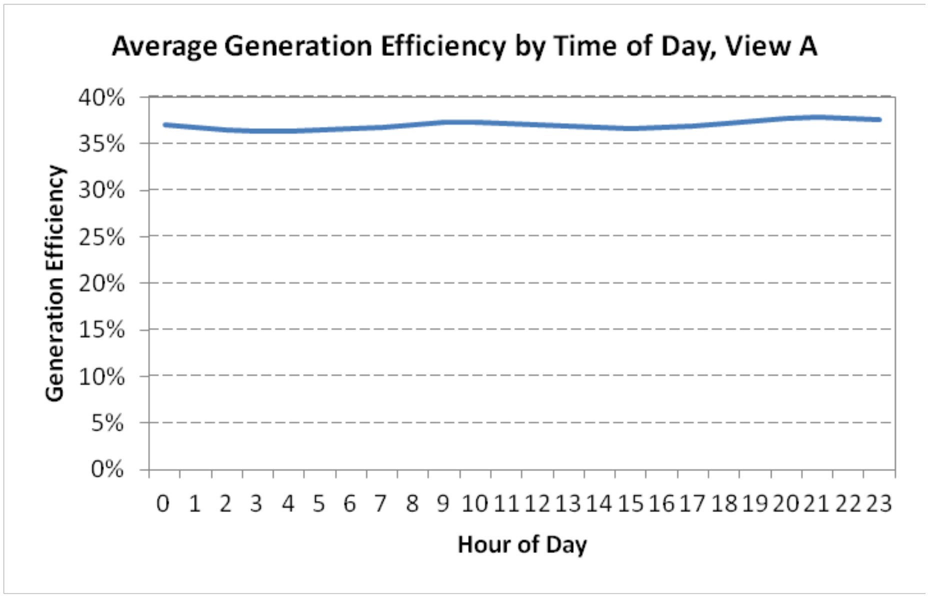
[5] A note of caution: If the user selects a date that is too recent, the AMPD tool may warn the user that only preliminary data are available for that date. At the time of this study, for example, summer 2012 data were still in a preliminary state, so a range from summer 2011 was selected instead, which did not generate a preliminary data warning.

[6] For this example, the "Query" option was selected in the AMPD tool, focusing on the "Emissions" data set, organized by "Monitoring Location."



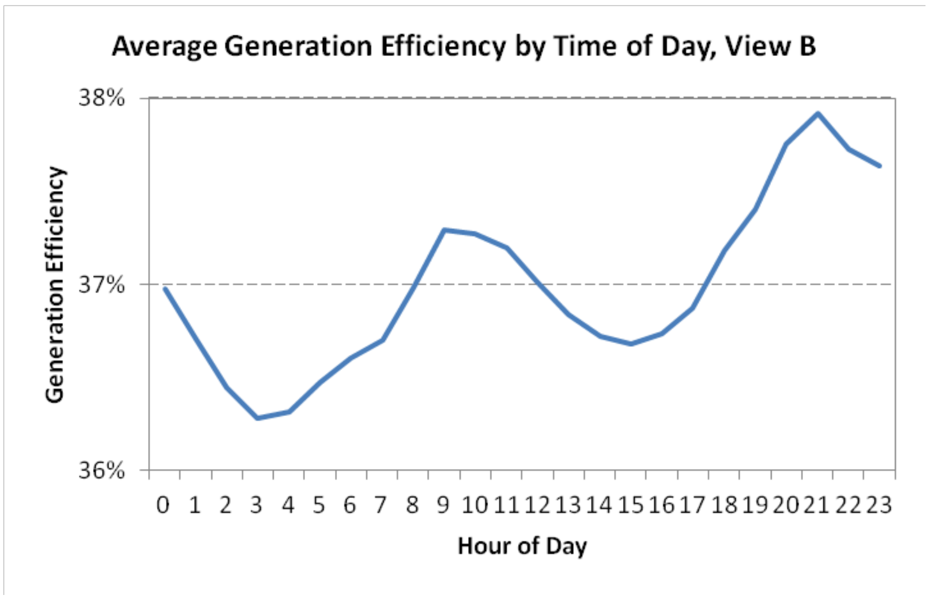


Figure A-4 Aggregated hourly electricity generation efficiency in August 2011, from Texas plants reporting emissions to the EPA Clean Air Markets Program

In Figure A-4, "View A" shows that time-of-day variations in electricity are fairly small compared to the magnitude of the average generation efficiency; "View B" is a closer look at the range over which generation efficiency varies, which reveals small drops in efficiency during early morning and the afternoon. The average efficiency and low overall variability is summarized numerically in Table A-4.

Table A-4 Variability in Hourly Electricity Generation Efficiency in August 2011, From Texas Plants Reporting Emissions to the EPA Clean Air Markets Program

Timeframe	Average Efficiency	Range Between Maximum and Minimum Efficiency	Range/Average	Standard Deviation
August 2011	37.0%	1.6%	4.4%	0.46%

The overall consistency of values in Figure A-4 and Table A-4 suggests that, for this specific case, time-of-day variations in generation efficiency could be neglected by a building owner's engineer during a site-to-source energy calculation if the included plants dominate the generation plants. If that were the case, the building owner's engineer could assume an average plant generation efficiency of 37% for August calculations.

One major limitation of this example, however, is that the data set excludes plants that do not report emissions to the Clean Air Markets program. For example, the contribution of renewable power systems to the grid is not captured. So, although the above example demonstrates a general process for examining the impact of time-of-day variations in generation efficiency, the inputs require improvement. For a building owner's engineer to effectively assess the significance of these variations without access to grid analysis software, data sets or summary tables will be needed that capture local generation mixes and hourly efficiencies more comprehensively.

Another limitation of this simplified approach is that the inclusion of electricity generation in the state-level aggregation was based solely on the location of the power plant; this approach does not account for imports and exports of electricity across state lines. While this simplification may be acceptable to a building owner's engineer considering energy storage for a single site, a utility that is considering a larger project may opt to leverage grid analysis software to account for energy flows more accurately.

A.5 Precombustion Contributions to Source Energy

Source energy can also be defined to account for "precombustion effects," including "extraction, processing, and transportation" of fuels used in power plants (Deru et al. 2007). Estimates of precombustion contributions to source energy are not typically available at hourly timescales, but annual average estimates of precombustion contributions to source energy for electricity generation are available in the appendix of the report titled, *Source Energy and Emission Factors for Use in Buildings* (Deru et al. 2007). For example, in the ERCOT interconnection, Deru et al. estimate that an average of 0.253 kWh of additional energy was lost during precombustion activities for every 1 kWh of electricity delivered to consumers in 2004.

A.6 Derivation of Average and Marginal Emission Factors

The OpenEI website referenced in Section 3.2 provides hourly average emission factors developed through a 2011 NREL project (OpenEI 2012). The emission factors were determined with a commercial unit commitment and hourly economic dispatch model that simulates the financial operation of the electric power system with a constrained transmission grid based on a direct current power flow. The model commits and dispatches electric generating units in order to minimize the production cost of the system as a whole while meeting electricity demand and reliability reserve requirements. The model simulated the dispatch of electricity generating units within each of the three synchronous interconnections (the eastern interconnection, WECC, and ERCOT). Each interconnection was modeled separately, and hourly electricity transfers between eGRID subregions were tracked for use in the emission calculations. Utilities and load areas were sorted into applicable eGRID subregions.

The 2011 NREL project also included a preliminary examination of marginal emission factors beyond the scope of the datasets at the OpenEI website. Base case and load decrement cases were simulated to estimate changes in emissions that result from changes in load. For each eGRID subregion, the load decrement case involved reducing loads in the subregion by 500 MW during every hour of the year. The size of the load decrement (500 MW) was chosen to be large enough to represent more than one generator on the margin, but small enough that it is expected to reflect marginal effects rather than major changes in generation. Alternative load decrement sizes were tested, and lower values (less than 200 MW) led to unstable results.

Marginal emission factors were estimated by comparing each base case and load decrement case to calculate emission changes per unit of load change. This work was leveraged to produce the marginal emission factors for the calculations used in Section 5.3.

Appendix B Additional Background for Demonstration Data Analysis

As indicated in Section 5.0, pre-retrofit data were not available for the demonstration sites, and their monitoring periods did not include any baseline days, so a simplified mathematical model of baseline performance was derived using data from hours when the DX system was the primary source of cooling.

The approach leveraged a combination of one-minute-interval measured data and hourly aggregation. Starting with subhourly measurements was important for capturing peak demand (kW) values associated with DX RTU performance because DX compressors can cycle between idle and cooling modes multiple times within an hour.

One-minute measurements of DX power were binned into three groups based on which mode of operation the DX system was in when each measurement was taken. The three modes were cooling, fan, and idle.

The cooling group was further subdivided into two groups, depending on whether the DX system was assumed to be in transition between modes or relatively stable. The transition minutes were assumed to include: (1) the minute before a DX system switches from cooling to another mode; (2) the first two minutes after a DX system switches to cooling. This approach isolates minutes that may be split between two modes, as well as minutes when power input may fluctuate immediately after cooling is initiated.

DX power during the non-transitional cooling minutes was then correlated with ambient air temperature to produce a simplified linear regression model of baseline performance for that mode of DX operation. Each equation takes the general form:

$$Y = \beta_0 + X\beta_1 \qquad \text{(B-17)}$$

Here, Y is DX power in kW, and X is ambient air temperature in degrees Fahrenheit. Each coefficient β_o (intercept) and β_1 (slope) is summarized in Table B-5, along with the coefficient of determination, R^2 (the square of the correlation coefficient). The resulting correlations were only moderate in some cases, so the baseline regression models are considered to be only high-level approximations. This type of uncertainty is typical of field demonstration data, as discussed in Section 2.3.

Table B-5 Linear Regression Models Used for Baselines in Section 5.0

Site	Slope	Intercept	R^2
Site 1	0.02 kW/°F	3.87 kW	0.76
Site 2	0.02 kW/°F	3.08 kW	0.89
Site 3	0.04 kW/°F	2.05 kW	0.85
Site 4	0.06 kW/°F	2.18 kW	0.67

The linear regression model can be used for minutes when the system is assumed to be cooling and not in transition. For other modes of DX operation, average power values were estimated, as summarized in Table B-6.

Table B-6 Average DX Power (kW) Used for Baselines in Section 5.0

Site	Fan	Cooling Transition
Site 1	1.18	4.28
Site 2	0.97	3.39
Site 3	1.07	4.56
Site 4	1.27	6.66

After determining these values, the following algorithm was used to determine a maximum DX power for each hour of the baseline case:

- If no TES discharge occurred during the hour, then the maximum DX power in the baseline case was assumed to equal the maximum DX power in the case with TES.
- Otherwise, a new value was calculated for the maximum DX power for the hour in the baseline case. Since demand is still assumed to be based upon 15-minute averages, a baseline 15-minute interval was constructed for each hour. Time spent in different modes of DX operation during the 15-minute interval was estimated as follows:
    - The fraction of time in DX cooling mode was assumed to be the greater of the following two values:
        - The fraction of time spent in TES discharge mode for the same hour in the case with TES.
        - The maximum fraction of time spent in DX cooling mode when comparing all 15-minute intervals that month in the case with TES.
    - The fraction of DX cooling time spent in transition was assumed to be:
        - 3 minutes if total cooling time is 12 minutes or less. This reflects the presence of a transition between modes at some point in the 15-minute interval.
        - 0 minutes if total DX cooling time is 13-15 minutes.
    - Any part of the 15-minute interval not spent in DX cooling mode is assumed to be spent in DX fan mode.
    - The appropriate linear regression model from Table B-5 is applied to the fraction of time when the DX system is in cooling but not in transition. The appropriate average power value from Table B-6 is applied to the fraction of time spent in DX cooling transitions or DX fan mode.

A separate algorithm was used to determine average DX energy consumption for each hour of the baseline case:

- If no TES discharge occurred during the hour, then the average DX energy in the baseline case was assumed to equal the average DX energy in the case with TES.
- Otherwise, a new value was calculated. Time spent in different modes of DX operation was estimated as follows:

- The fraction of time in DX cooling mode was assumed to equal the fraction of time spent in TES discharge mode for the same hour in the case with TES.
- The fraction of DX cooling time spent in transition was assumed to be the lesser of the following two values:
  - The average fraction of time spent in DX cooling mode when comparing all hours that month in the case with TES.
  - The total time spent in DX cooling mode.
- Any part of the 15-minute interval not spent in DX cooling mode is assumed to be spent in DX fan mode.
- The appropriate linear regression model from Table B-5 is applied to the fraction of time when the DX system is in cooling but not in transition. The appropriate average power value from Table B-6 is applied to the fraction of time spent in DX cooling transitions or DX fan mode.

This simplified approach reflects the limited amount of building data available within the scope of this project, which leveraged data from previous demonstrations conducted by project partners; other projects with better access to baseline data can employ other analysis methods as discussed in Section 2.3.

Appendix C Additional Simulation Results

The figures in this section summarize results from the nationwide simulations detailed in Section 6.3. Three building types were modeled, including a small office building, a standalone retail building, and a strip mall building.

In cases with TES, the TES system was used in the months of May through October to provide cooling between 12:00 p.m. and 5:59 p.m. This timeframe was selected as an illustrative example of a peak period, and it was based on a tariff schedule from a demonstration site discussed in Section 5.0. During other hours, cooling loads are met by packaged DX units. In baseline cases, TES is not used. Climate definitions and other modeling assumptions are provided in Section 6.3.

For each building type:

- The first six figures show how monthly peak demand differs between cases with and without TES. Each power difference is defined to be the power value from the case with TES minus the power value from the corresponding baseline case. The horizontal axis identifies the climate subzone where each building model was located. Across all climate subzones, the cases with TES successfully shift demand from on-peak hours to off-peak hours during summer months.
- The next two figures show how total energy consumption differs between cases with and without TES. The cooling electricity figure includes energy for DX and TES system components associated with space cooling, except for fans. (This differs from the cooling electricity figures for demonstration data in Section 5.0, which included fan energy.) Fan energy is tracked separately by the simulation program used for this study, and its values did not change between cases with and without TES. The facility electricity figure includes all electricity-consuming end uses in the building. The modeled cases with TES consumed more overall energy than their baseline counterparts, but the cases with TES reduce energy consumption during peak hours as intended. Demonstration data indicate that such energy results are possible for some TES applications.
- The final figure shows how load factor differs between cases with and without TES. The case with TES can have a greater or lower load factor than the baseline case, and the difference varies between climate zones. This study applied only one control strategy and did not attempt to optimize load factors, so load factor results in this section reflect indirect effects from an application that focused primarily on peak demand reduction. Future studies could examine whether variations in TES control strategies can improve load factor or other metrics.

The inputs used in this simulation study were informed in part by performance characteristics of a particular TES product, but a significant number of additional modeling assumptions and simplifications were also applied, and the validation activities completed during this project were considered preliminary steps. The preliminary results illustrate how impacts can vary if a test combination of TES system characteristics and controls is replicated in different settings. Future analyses could incorporate additional data to refine model inputs and conduct further validation activities to more accurately reflect the potential impacts of a particular TES application.

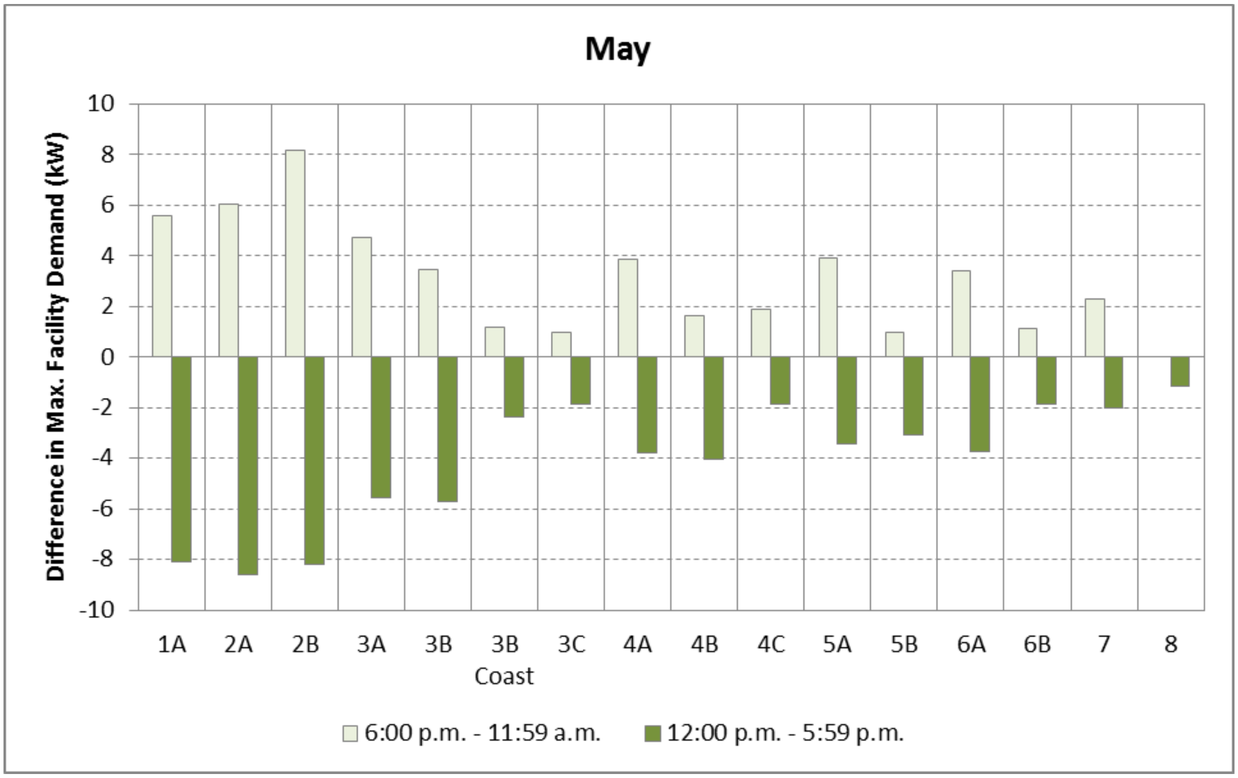


Figure C-5 Small office model: May facility electricity peak demand

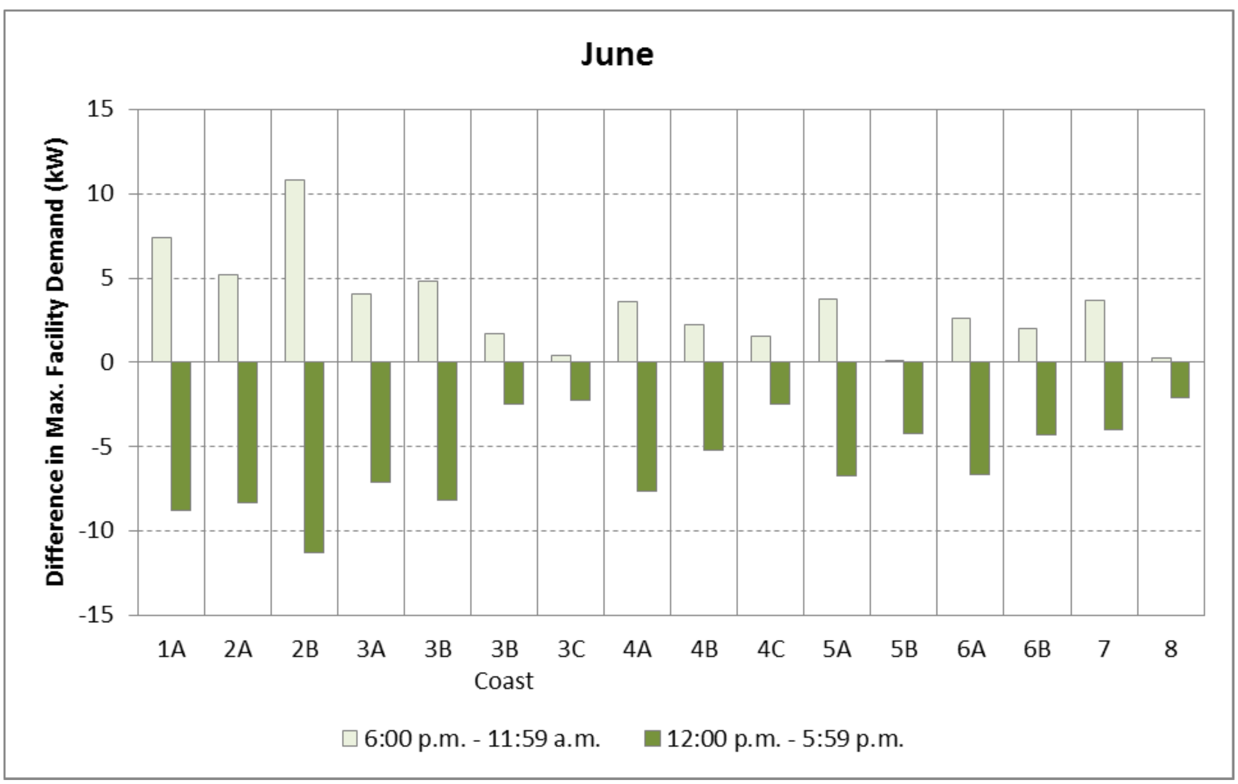


Figure C-6 Small office model: June facility electricity peak demand

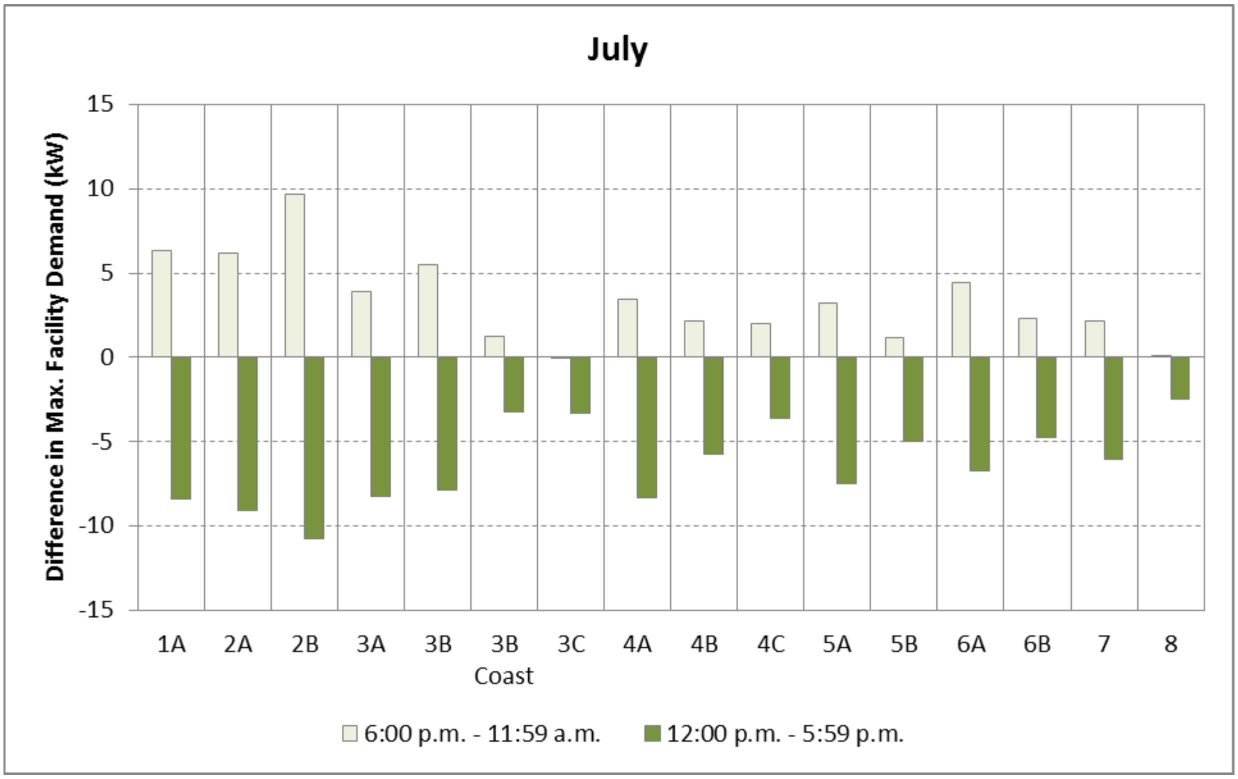


Figure C-7 Small office model: July facility electricity peak demand

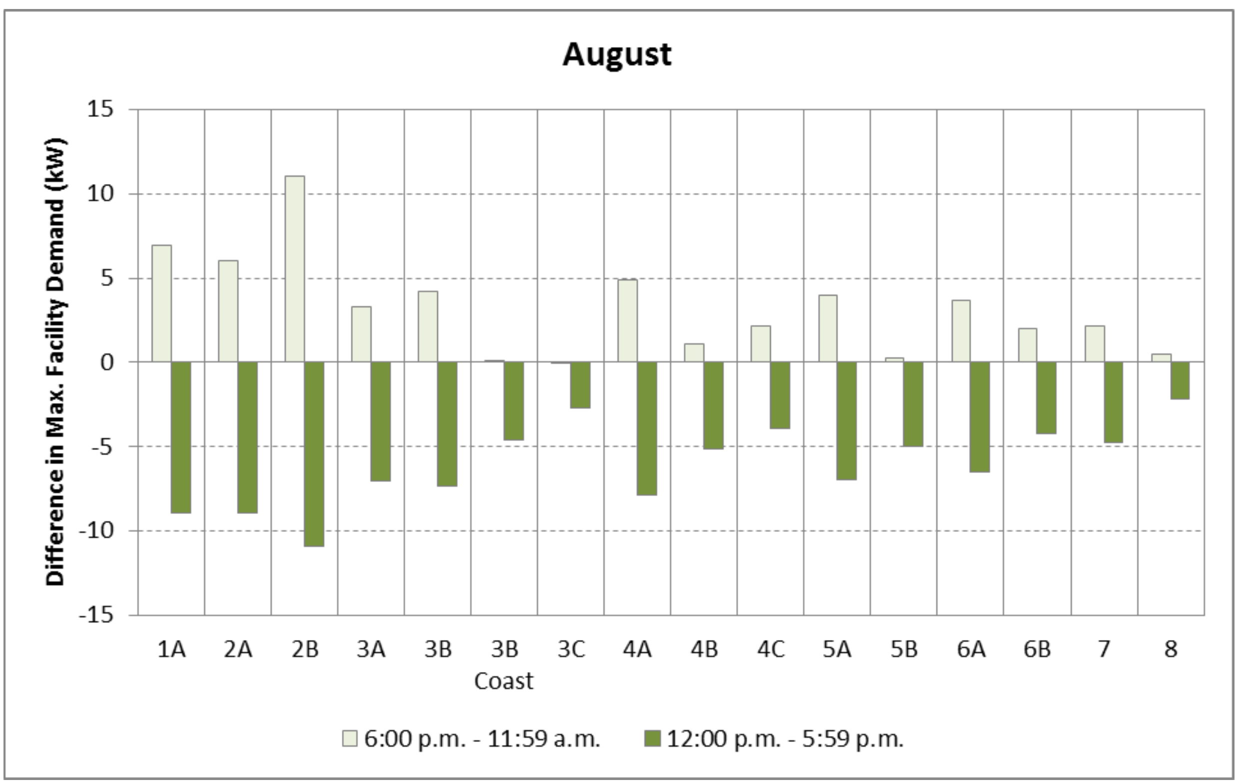


Figure C-8 Small office model: August facility electricity peak demand

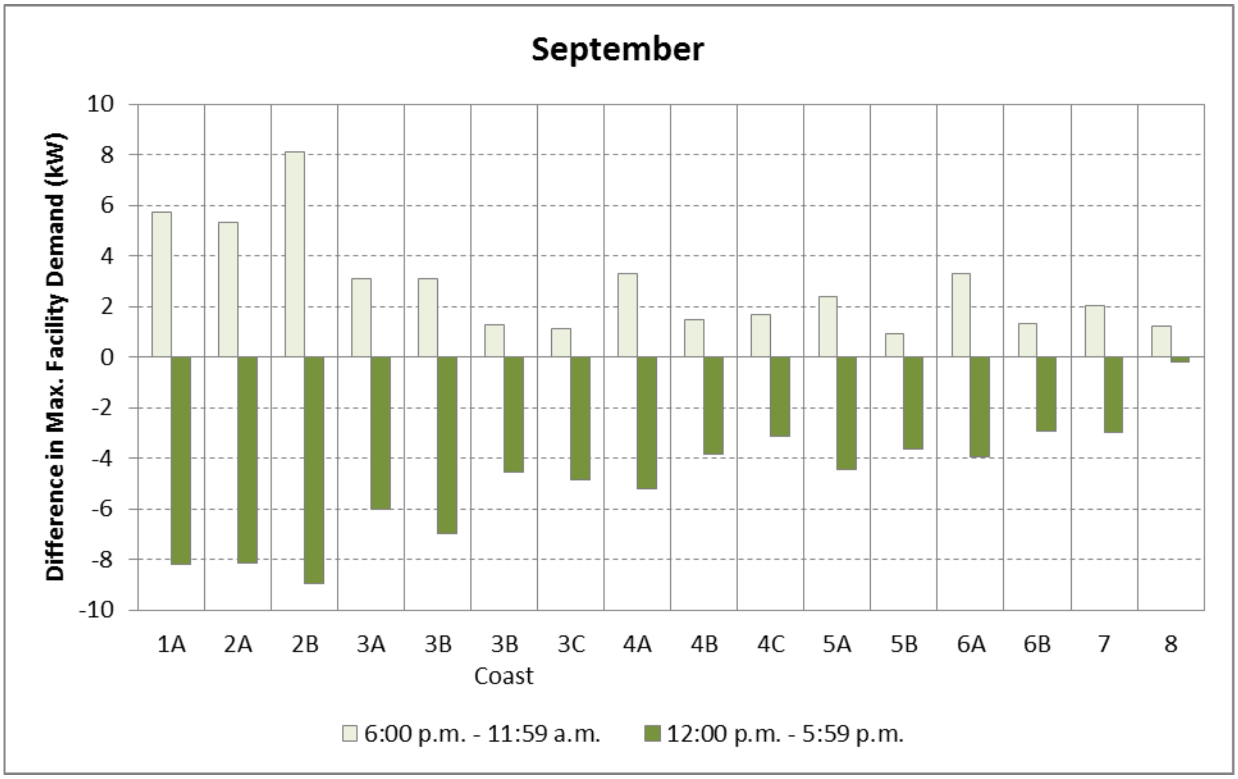


Figure C-9 Small office model: September facility electricity peak demand

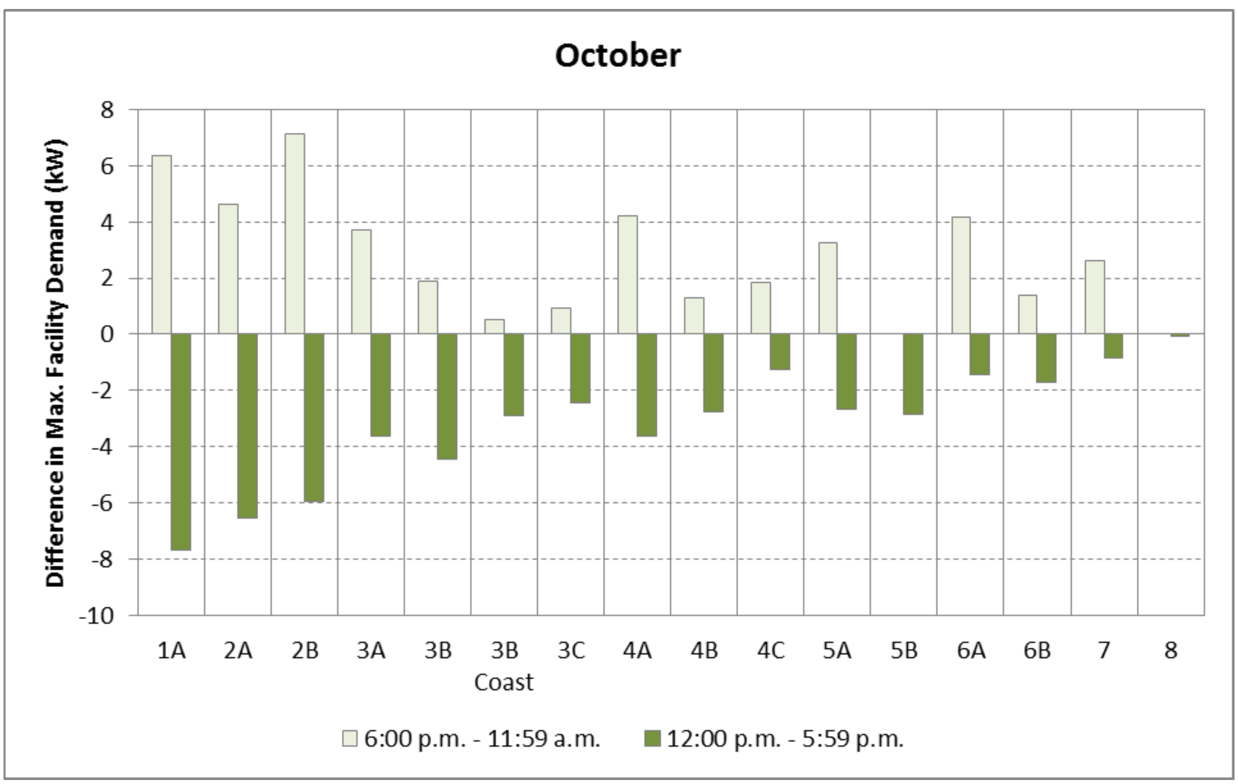


Figure C-10 Small office model: October facility electricity peak demand

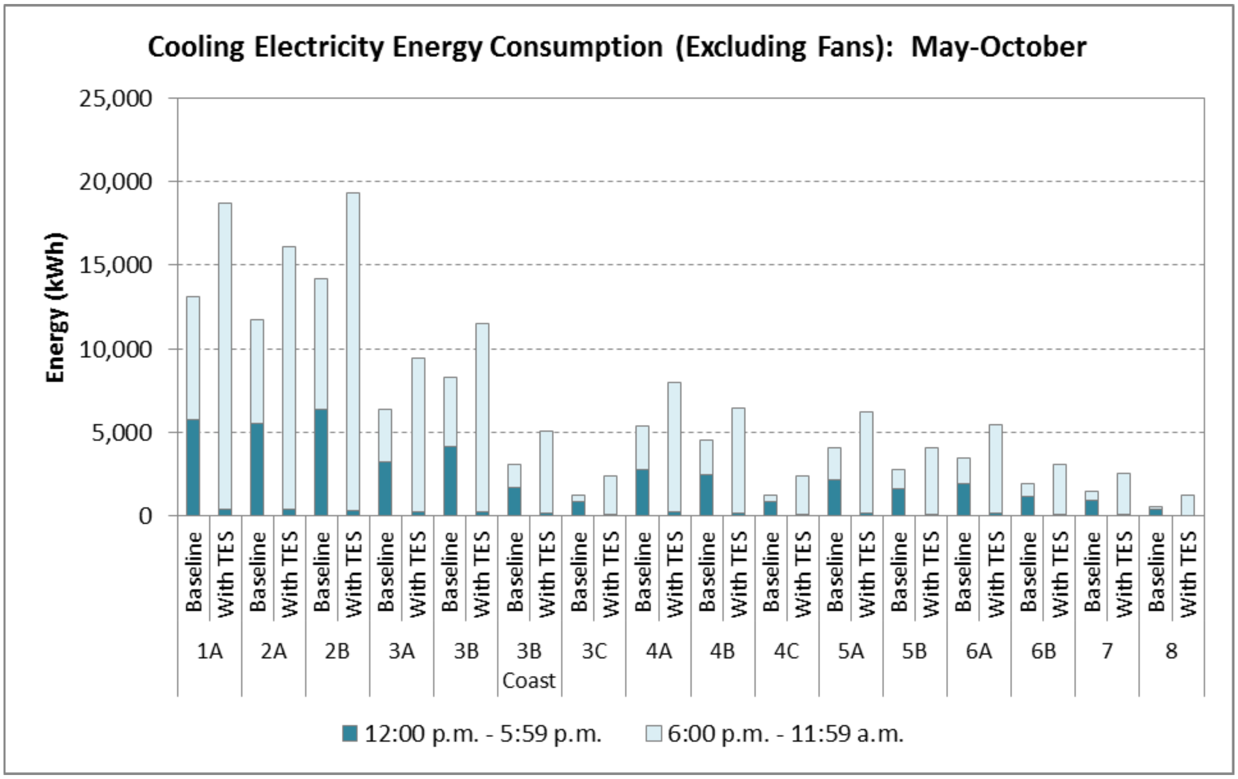


Figure C-11 Small office model: cooling electricity energy consumption

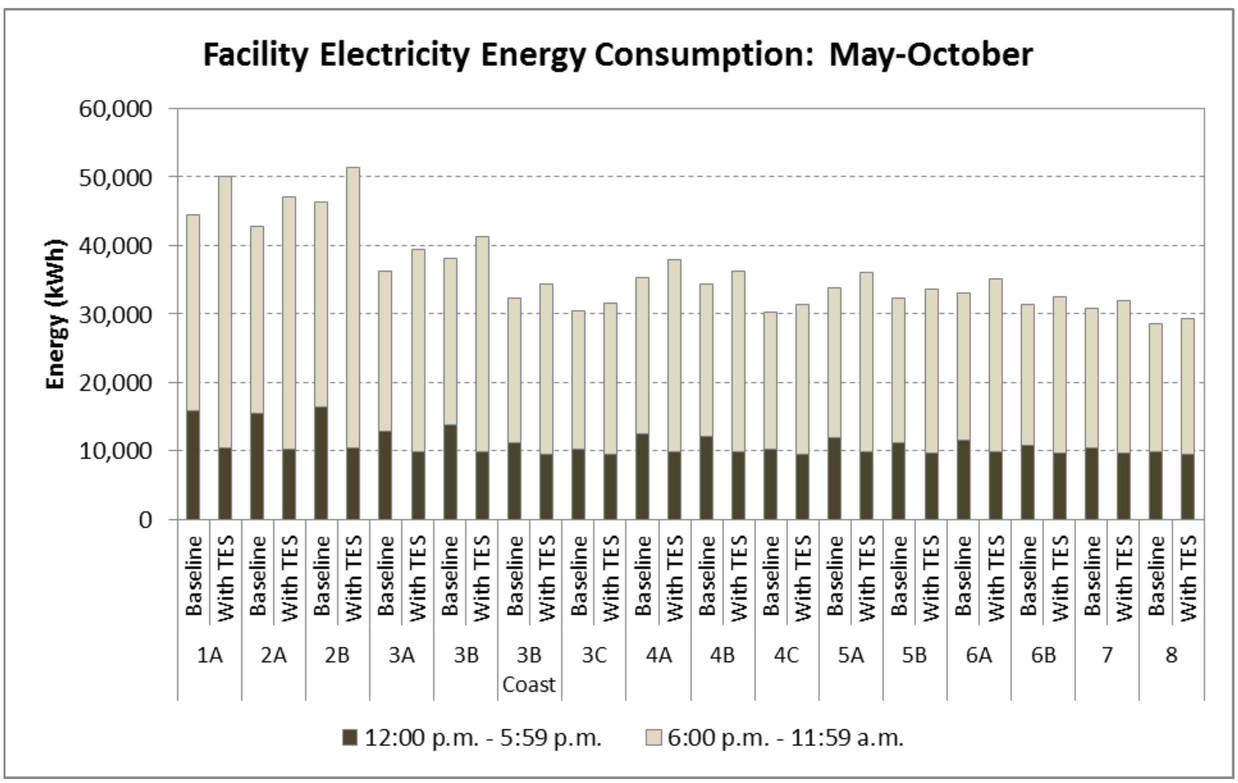


Figure C-12 Small office model: facility electricity energy consumption

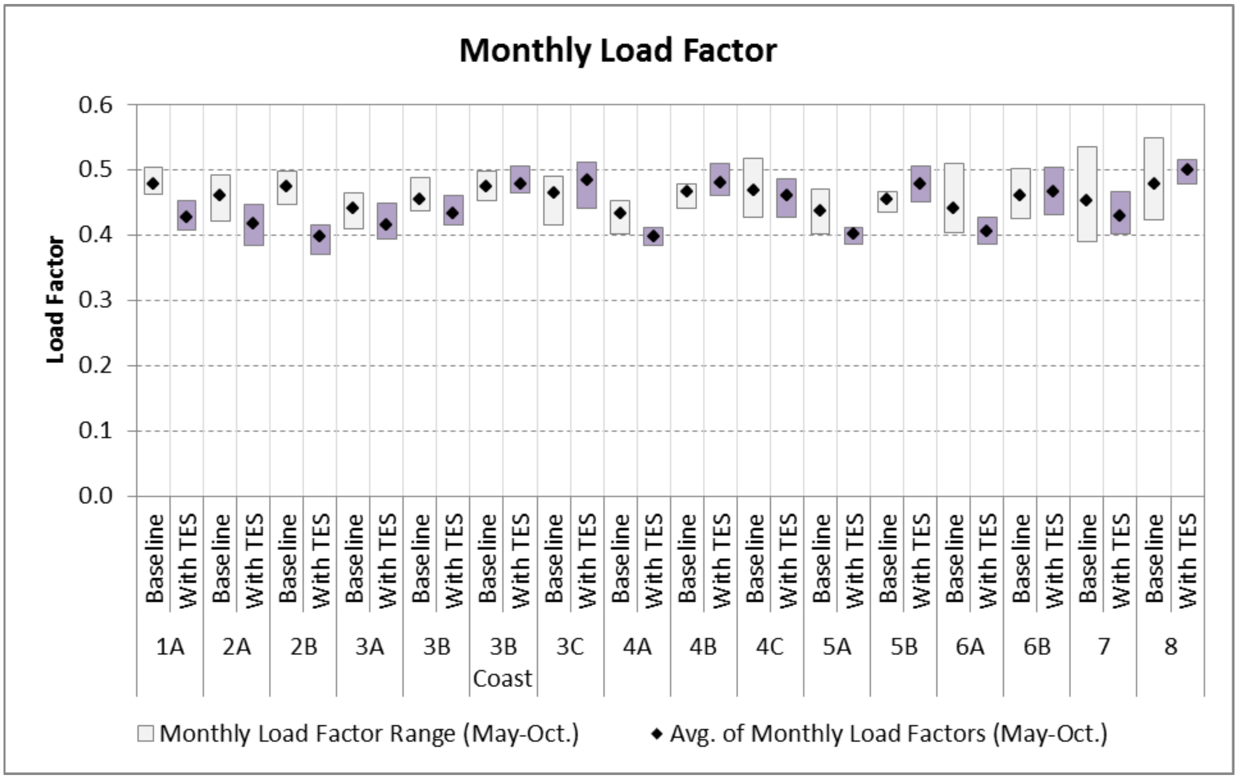


Figure C-13 Small office model: comparison of monthly load factors

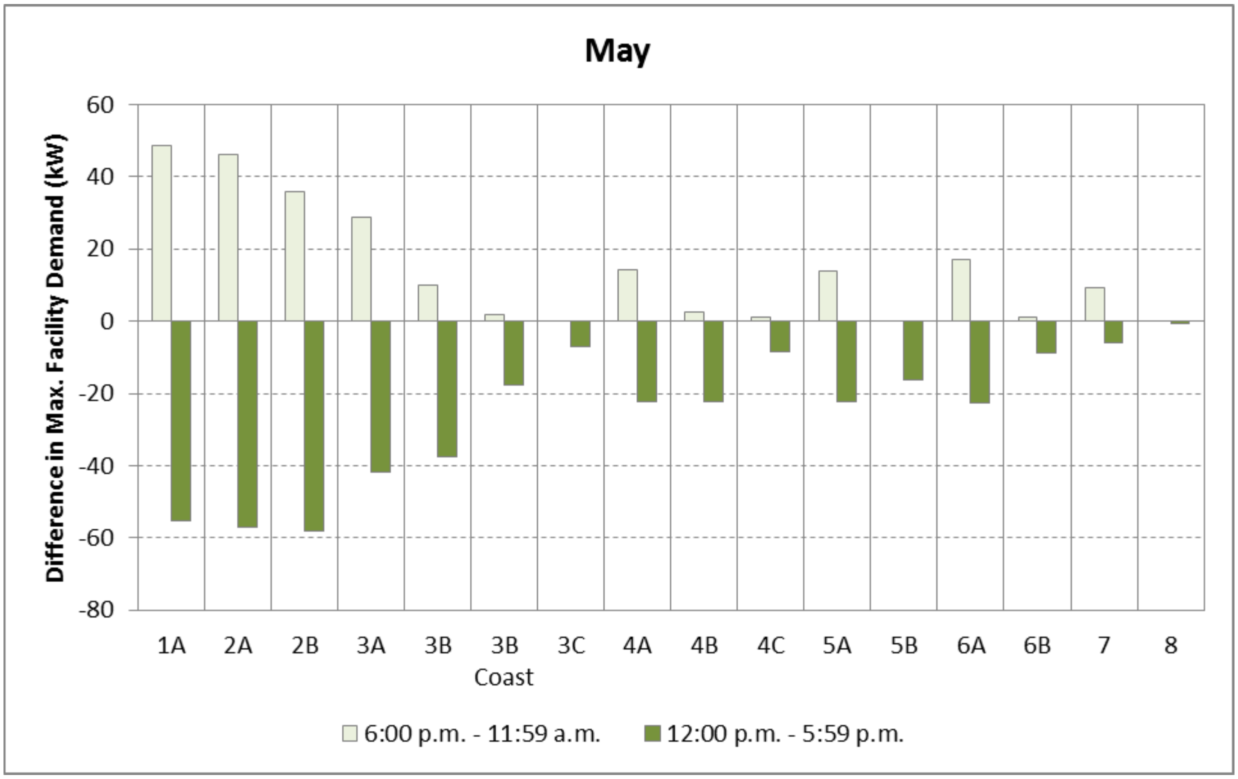


Figure C-14 Stand-alone retail model: May facility electricity peak demand

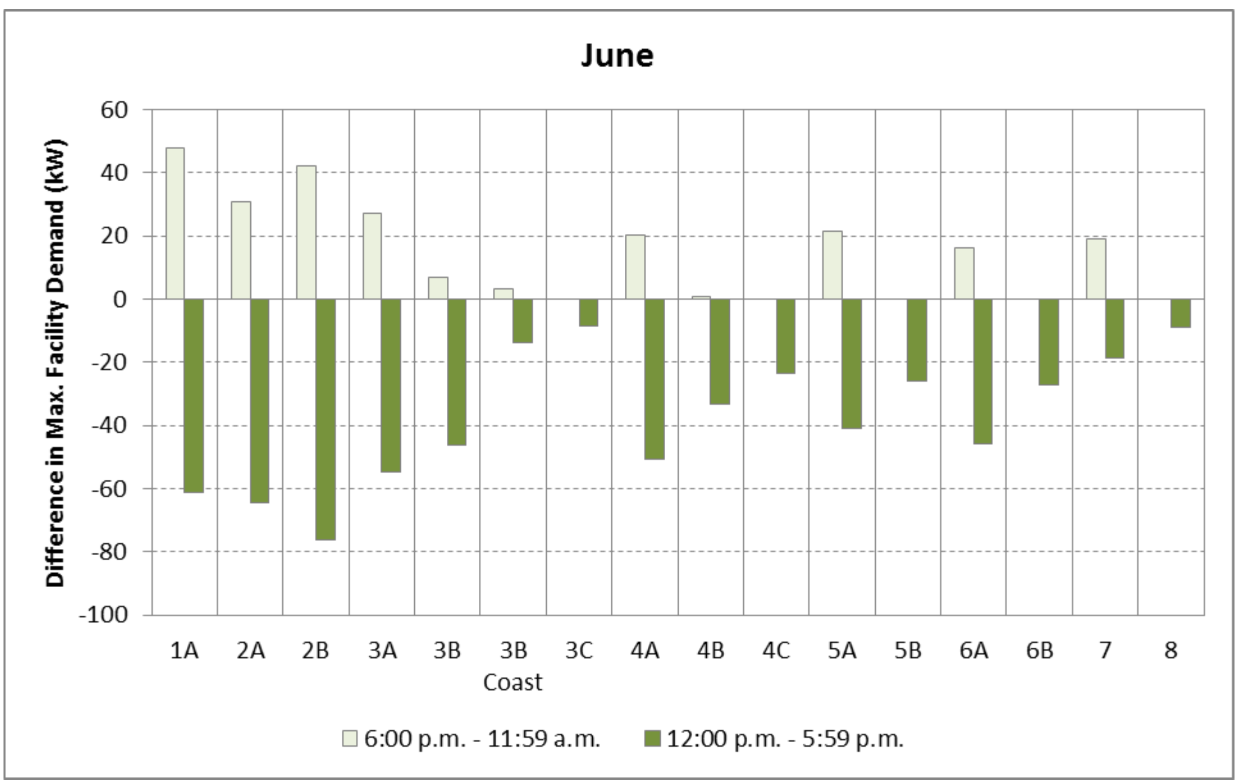


Figure C-15 Stand-alone retail model: June facility electricity peak demand

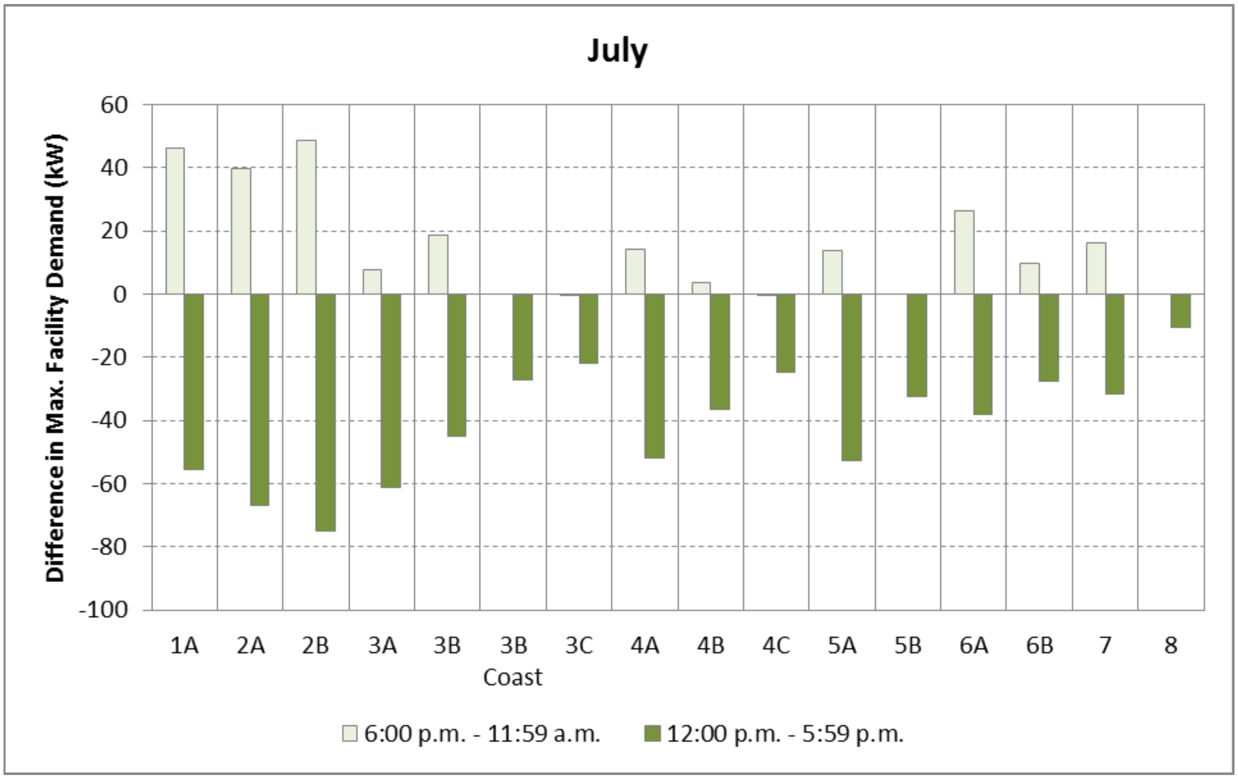


Figure C-16 Stand-alone retail model: July facility electricity peak demand

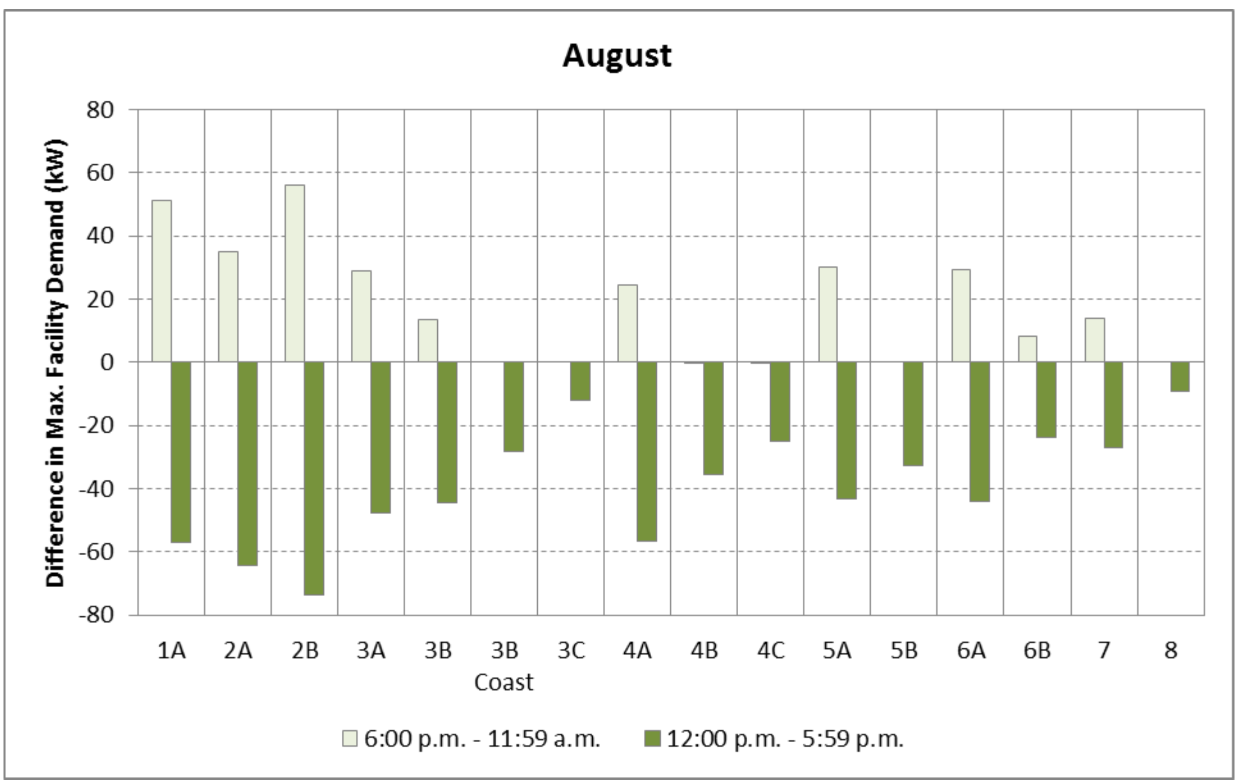


Figure C-17 Stand-alone retail model: August facility electricity peak demand

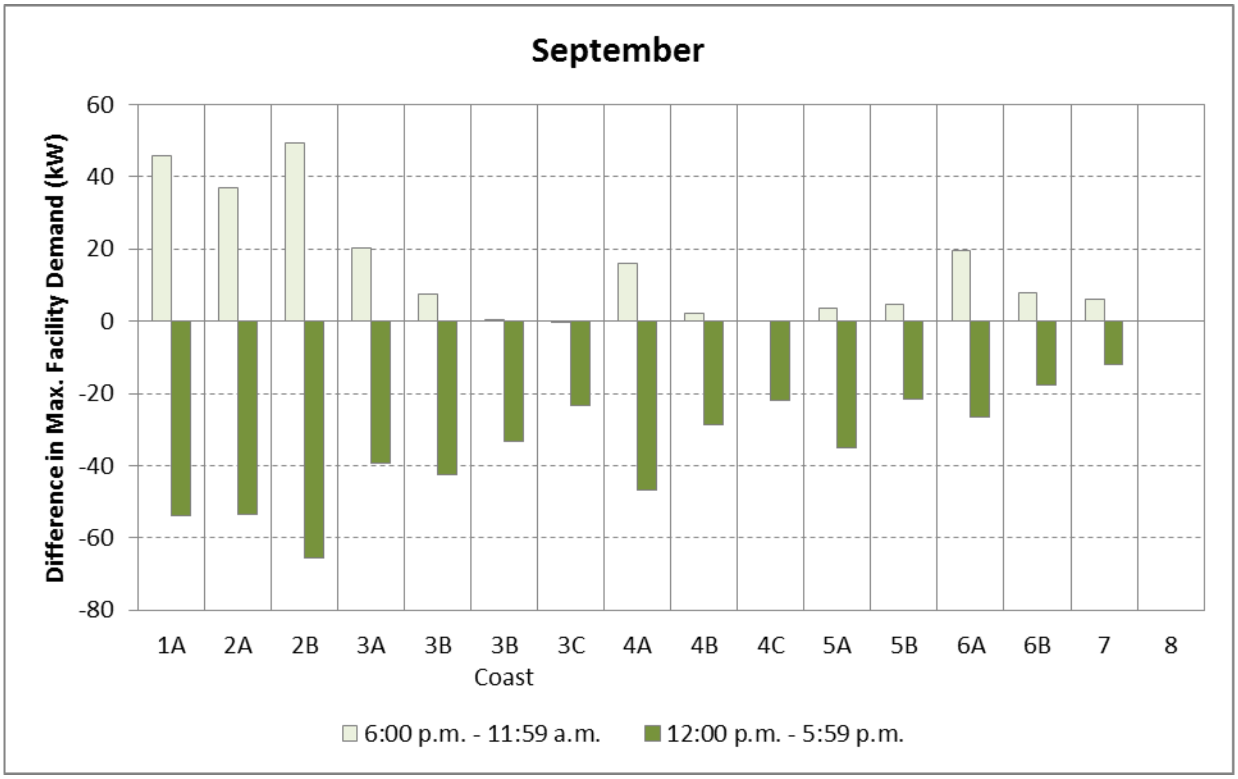


Figure C-18 **Stand-alone retail model: September facility electricity peak demand**

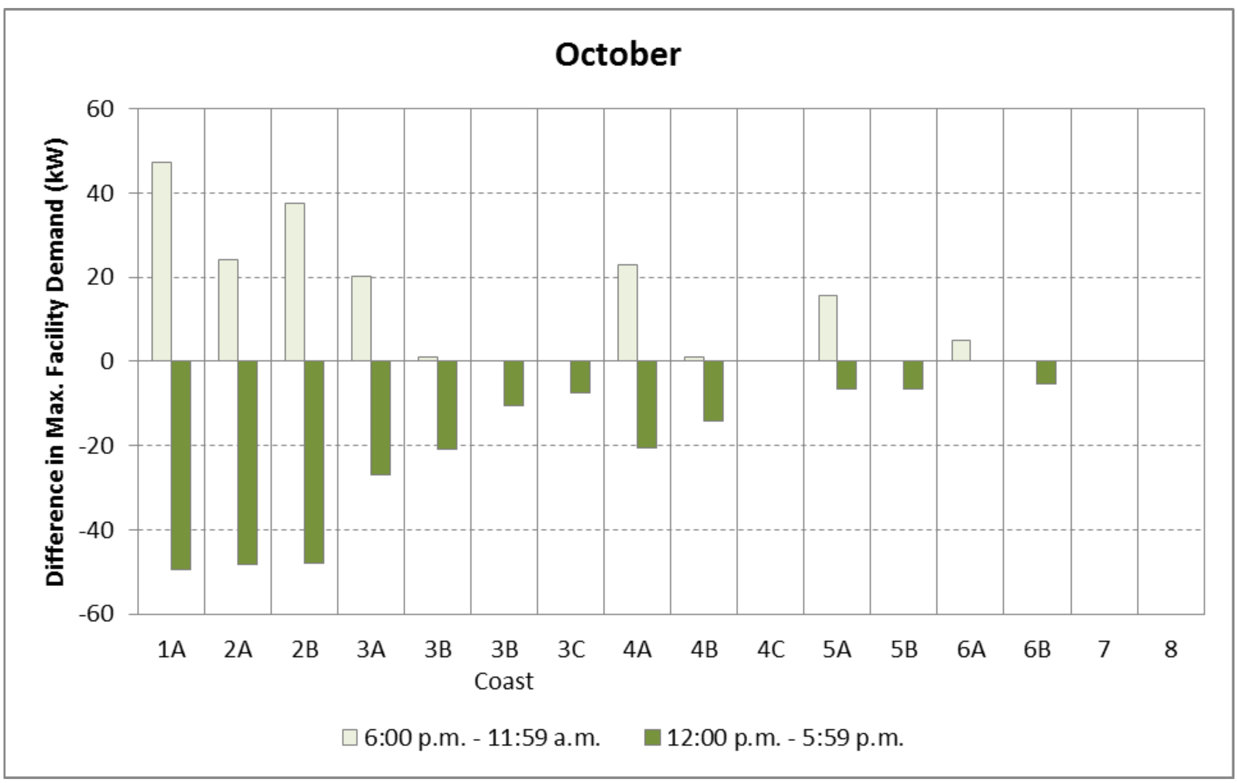


Figure C-19 **Stand-alone retail model: October facility electricity peak demand**

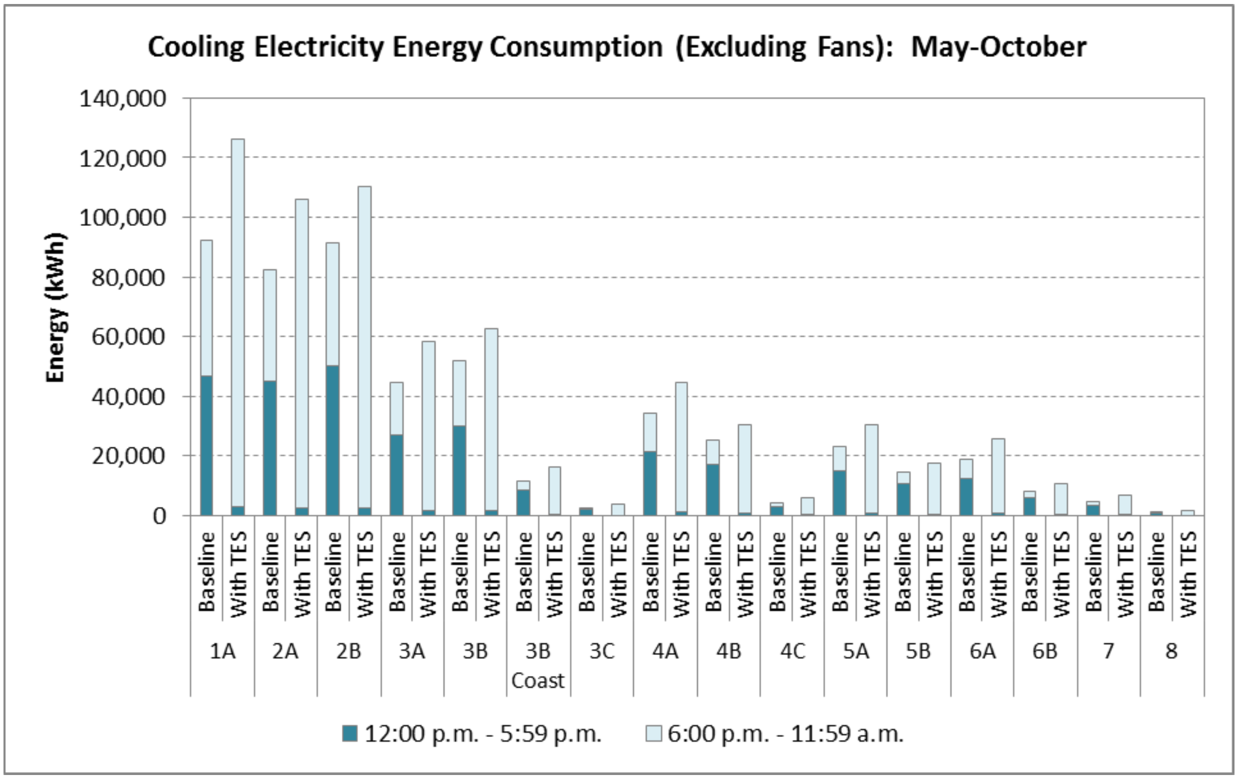


Figure C-20 Stand-alone retail model: cooling electricity energy consumption

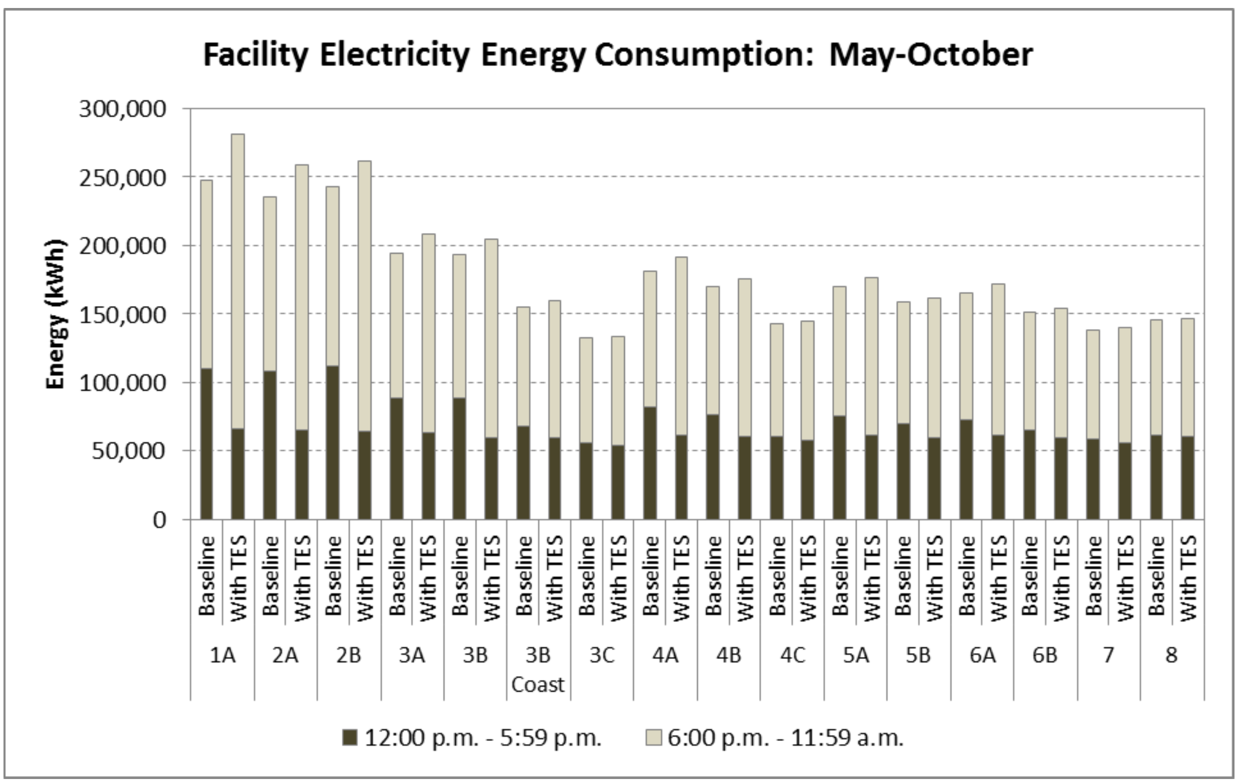


Figure C-21 Stand-alone retail model: facility electricity energy consumption

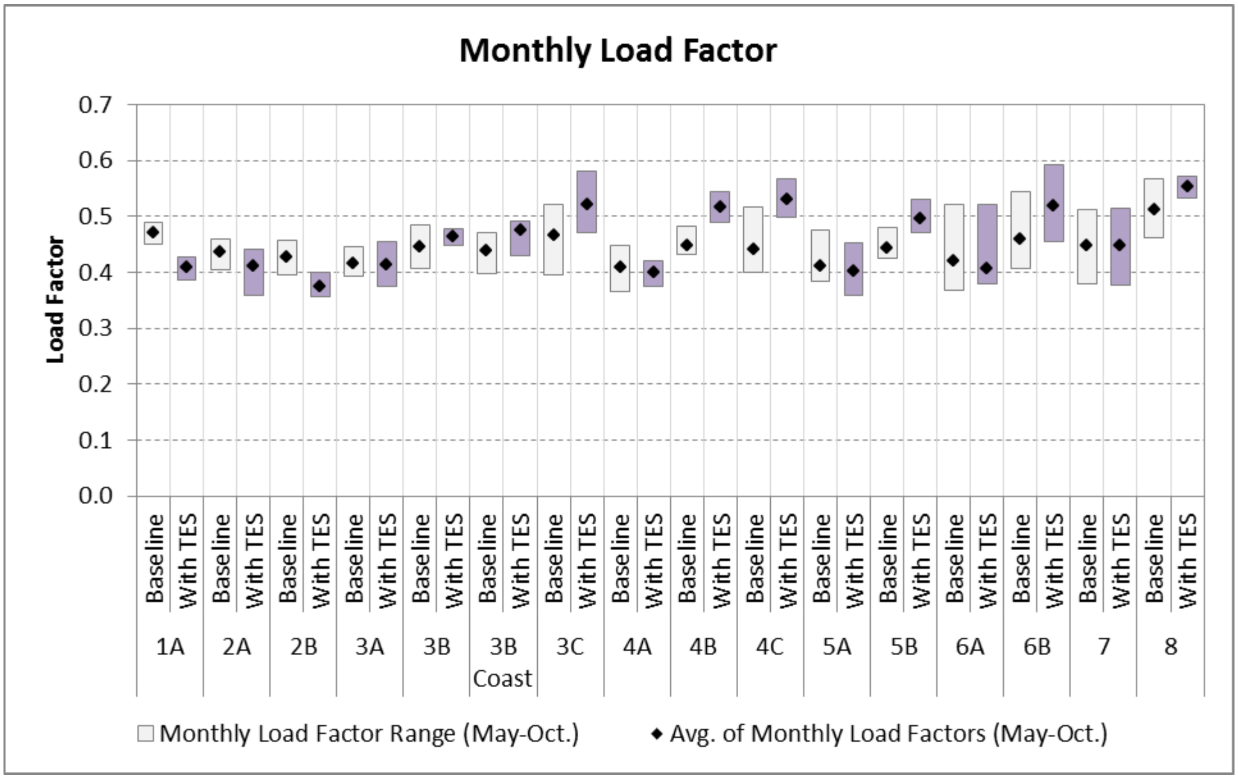


Figure C-22 Stand-alone office model: comparison of monthly load factors

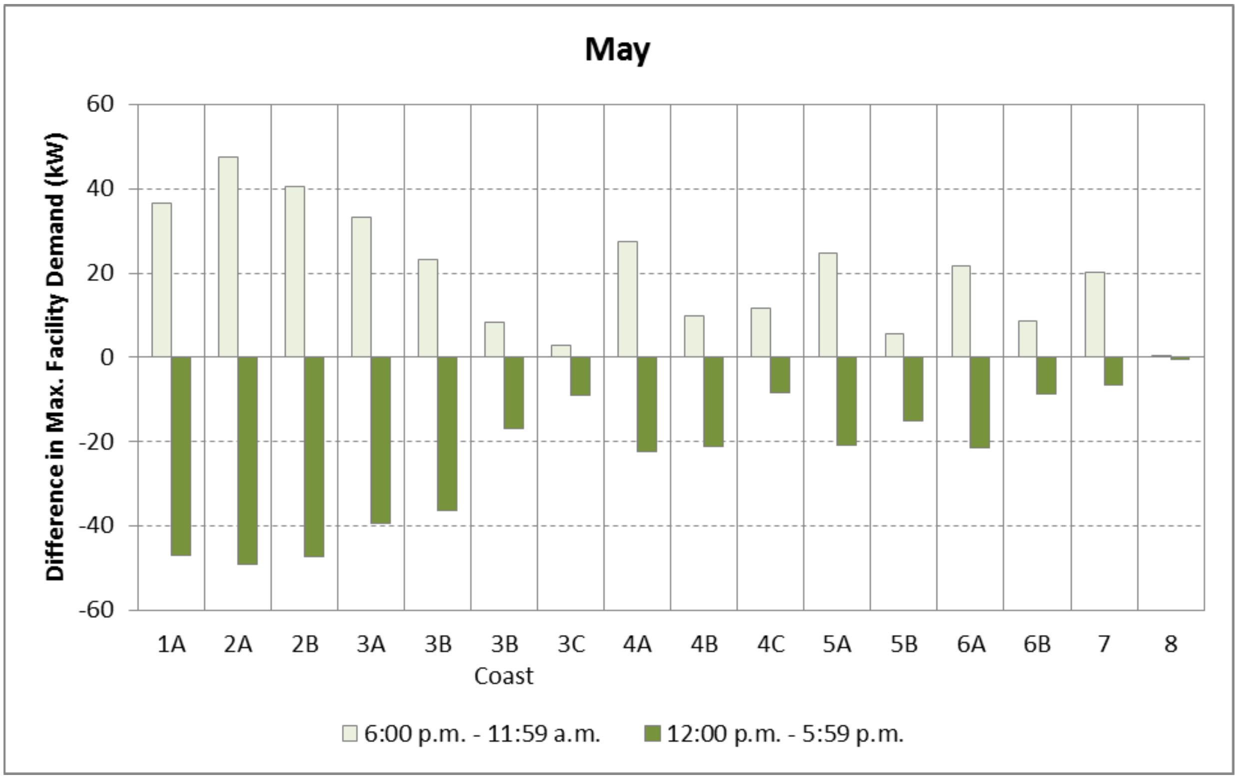


Figure C-23 **Strip mall model: May facility electricity peak demand**

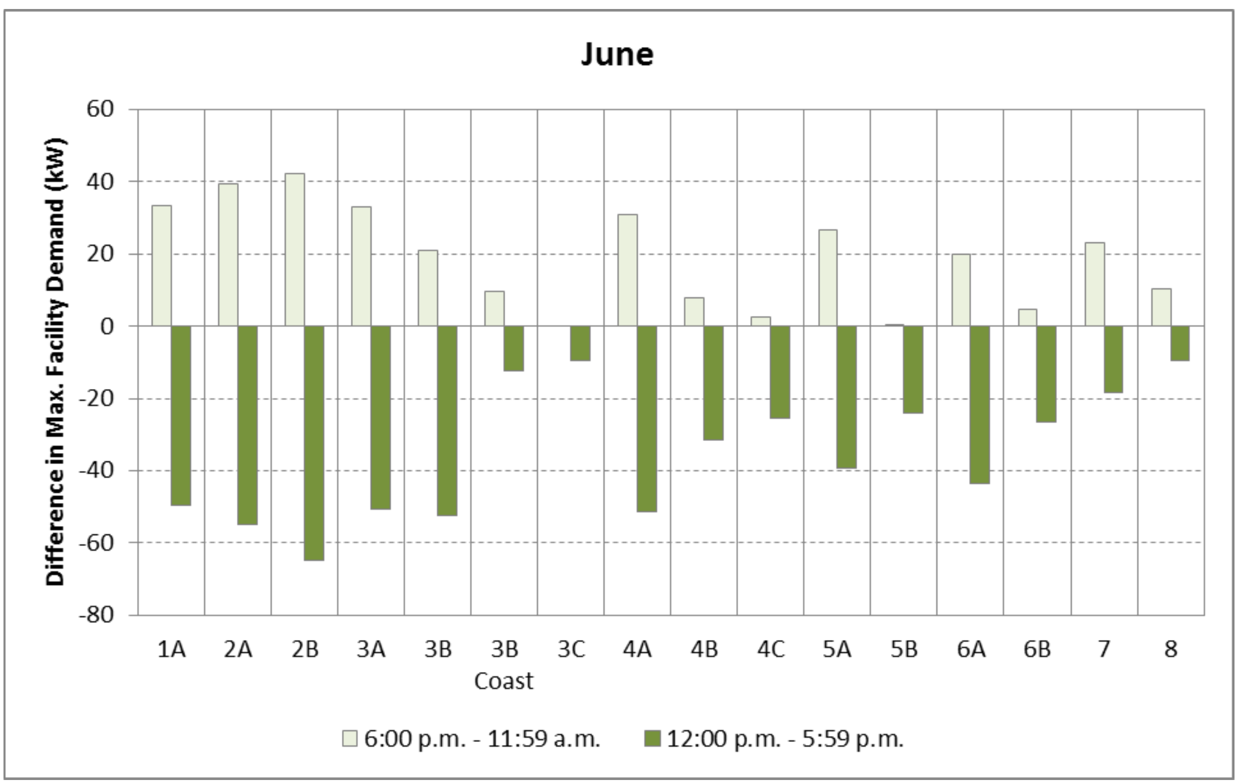


Figure C-24 **Strip mall model: June facility electricity peak demand**

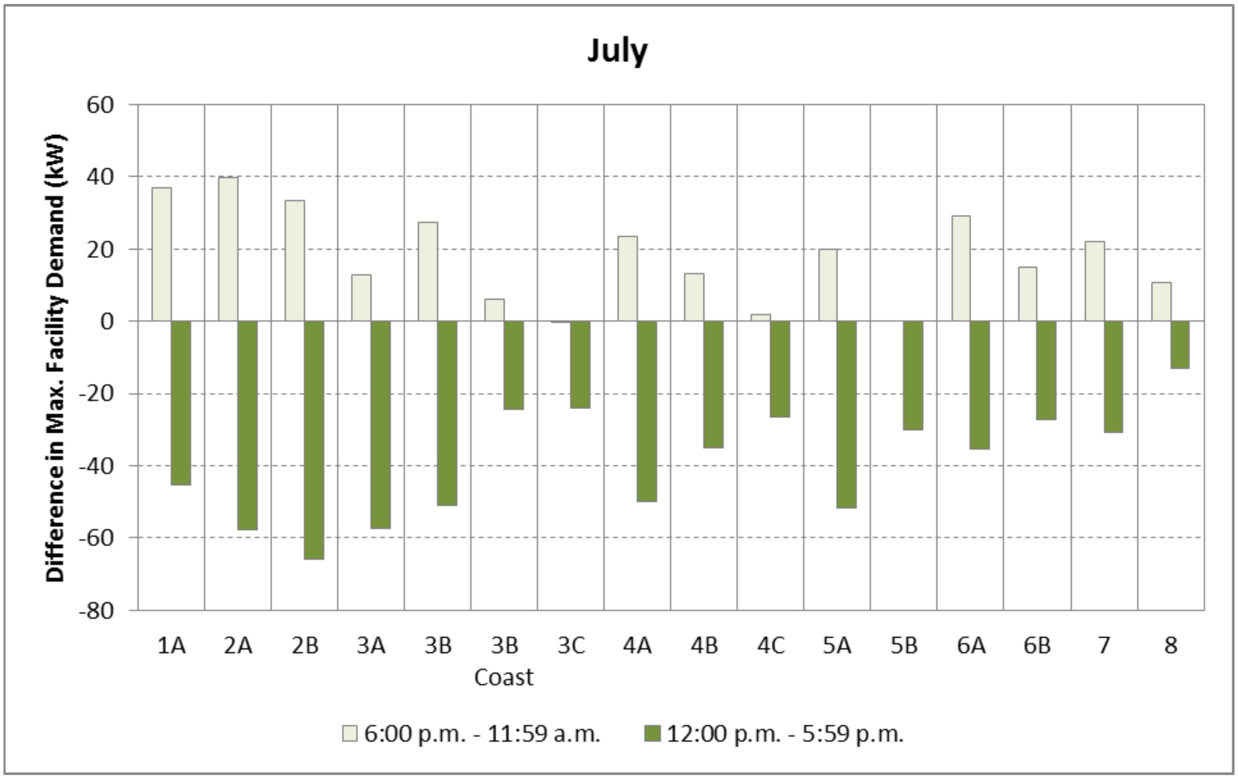


Figure C-25 Strip mall model: July facility electricity peak demand

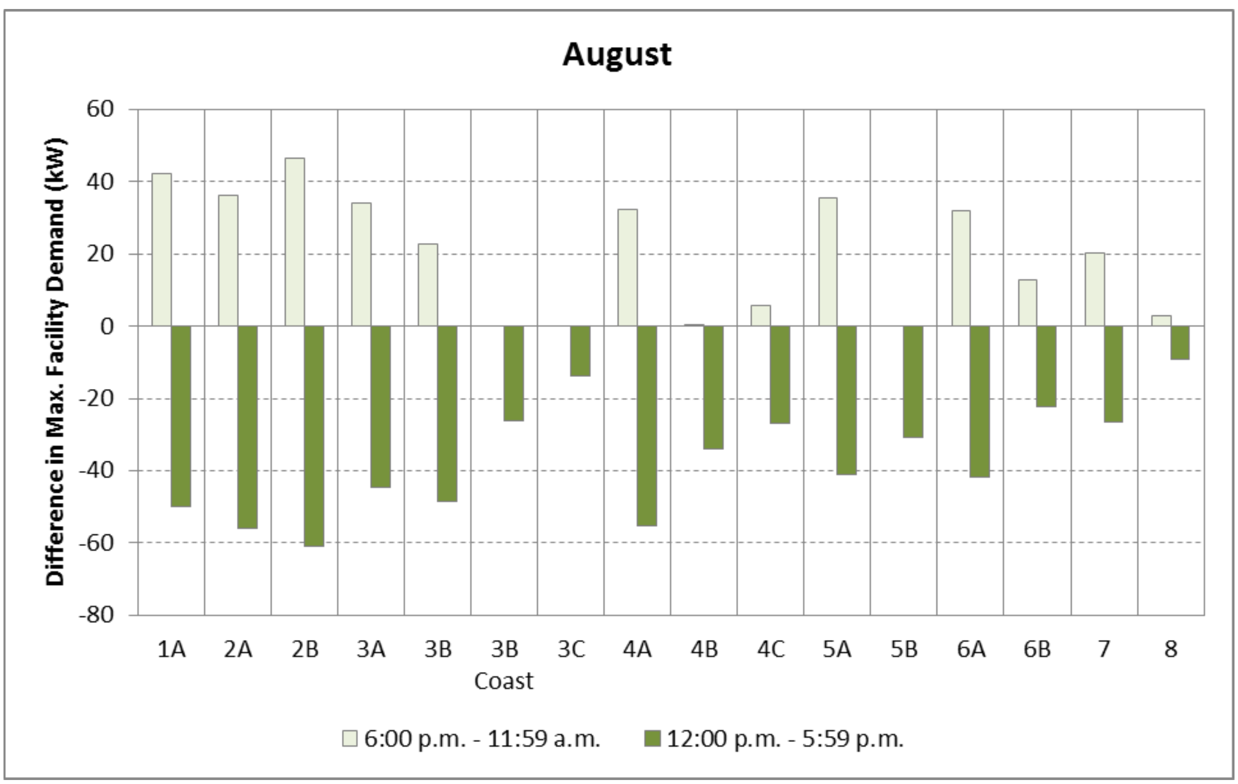


Figure C-26 Strip mall model: August facility electricity peak demand

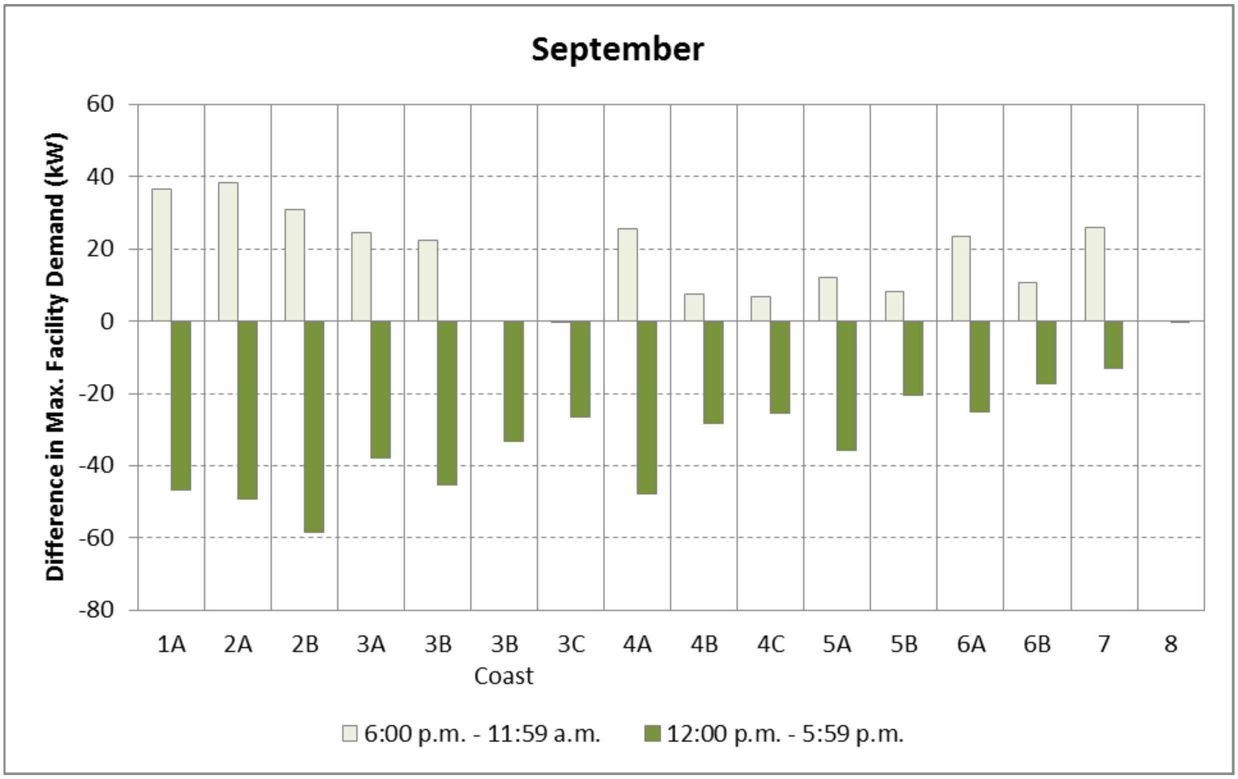


Figure C-27 Strip mall model: September facility electricity peak demand

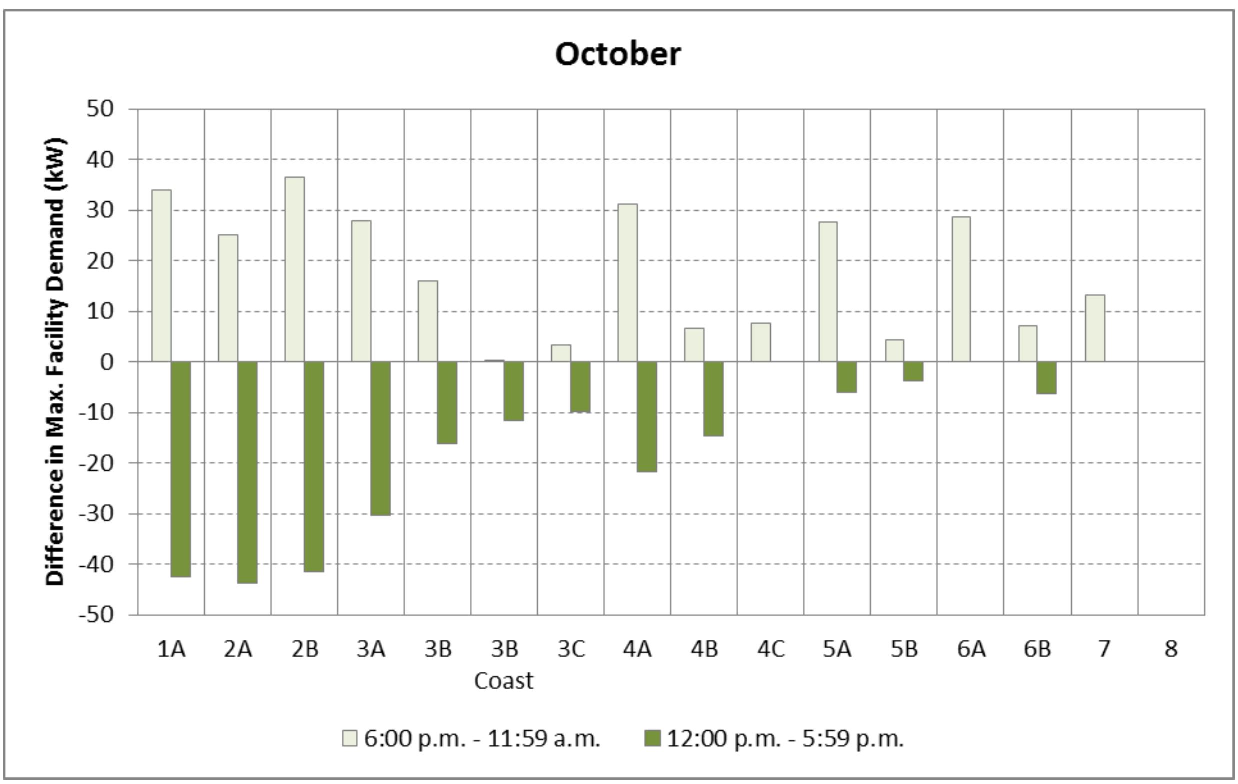


Figure C-28 Strip mall model: October facility electricity peak demand

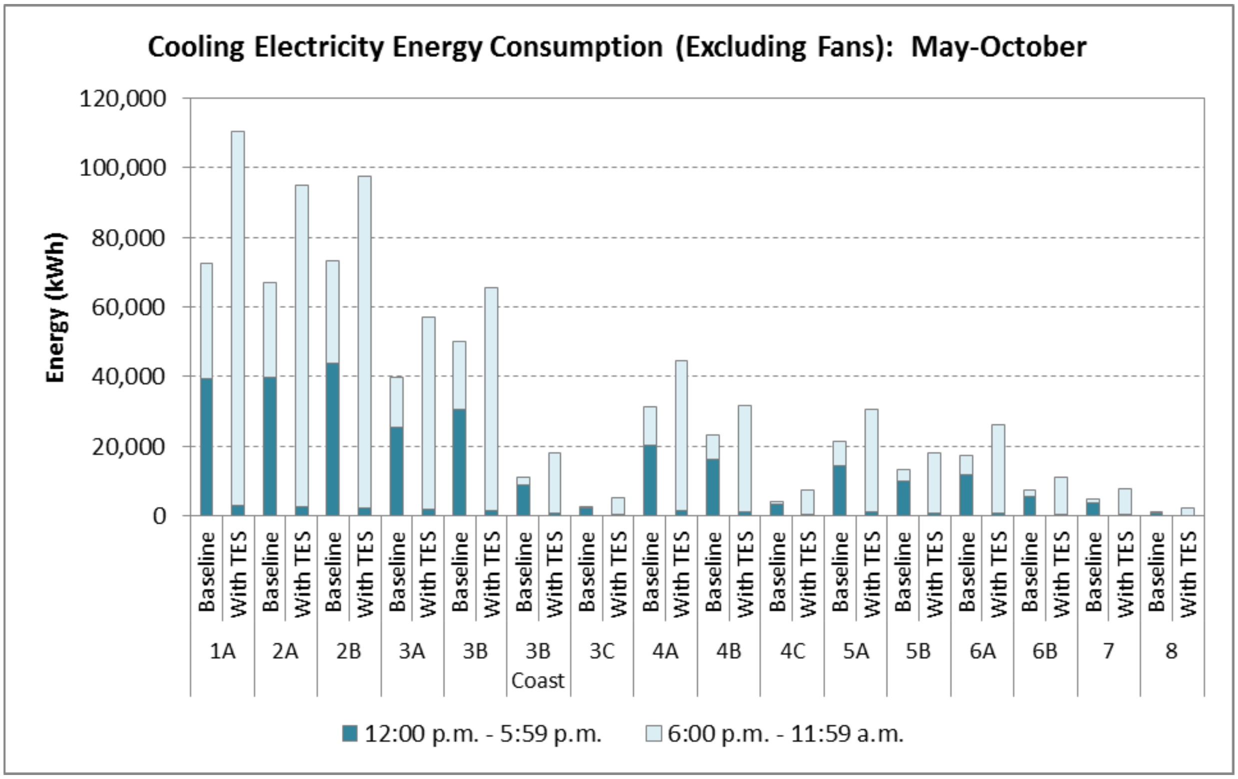


Figure C-29 Strip mall model: cooling electricity energy consumption

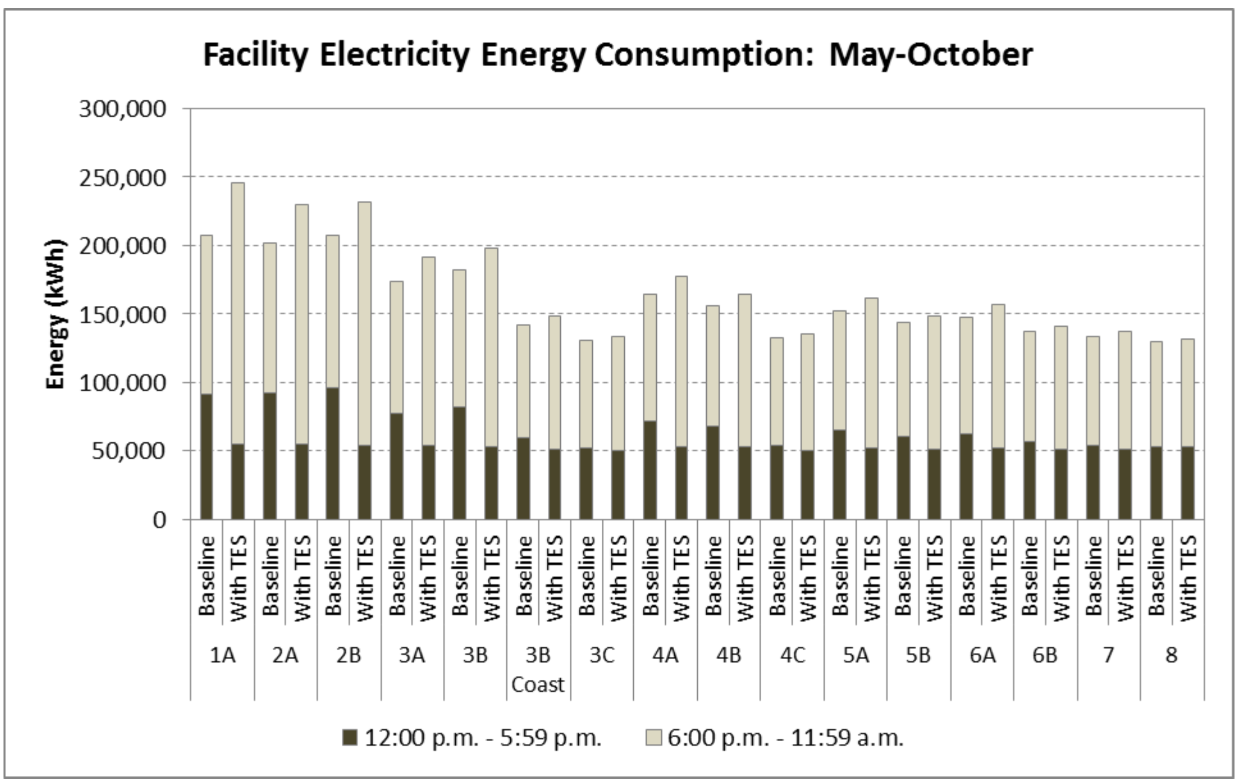


Figure C-30 Strip mall model: facility electricity energy consumption

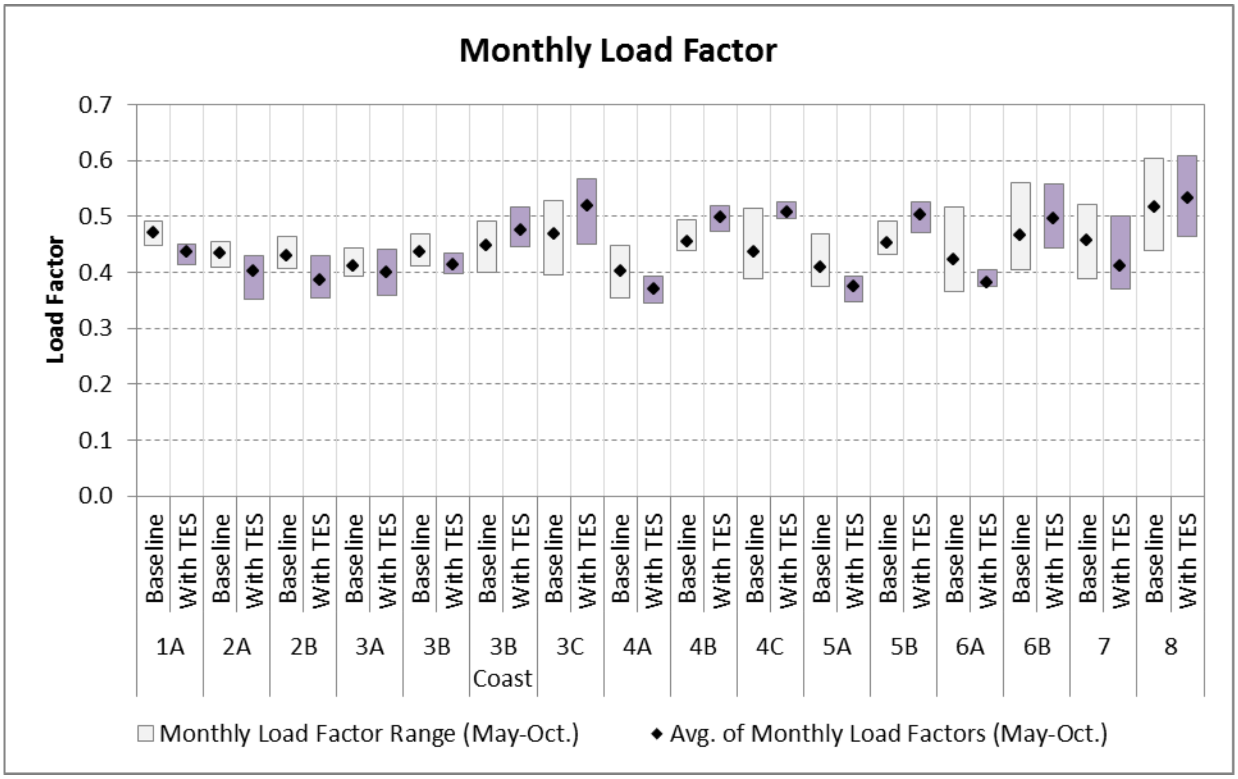


Figure C-31 Strip mall model: comparison of monthly load factors