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Energy Research and Development Division

FINAL PROJECT REPORT

Develop and Field Test Flexible Demand Response Control Strategies for Water Pumping Station and Industrial Refrigeration Plant

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PREFACE

The California Energy Commission's (CEC) Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission and distribution and transportation.

In 2012, the Electric Program Investment Charge (EPIC) was established by the California Public Utilities Commission to fund public investments in research to create and advance new energy solutions, foster regional innovation and bring ideas from the lab to the marketplace. The CEC and the state's three largest investor-owned utilities—Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company—were selected to administer the EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The CEC is committed to ensuring public participation in its research and development programs that promote greater reliability, lower costs, and increase safety for the California electric ratepayer and include:

- Providing societal benefits.
- Reducing greenhouse gas emission in the electricity sector at the lowest possible cost.
- Supporting California's loading order to meet energy needs first with energy efficiency and demand response, next with renewable energy (distributed generation and utility scale), and finally with clean, conventional electricity supply.
- Supporting low-emission vehicles and transportation.
- Providing economic development.
- Using ratepayer funds efficiently.

Develop and Field Test Flexible Demand Response Control Strategies for Water Pumping Station and Industrial Refrigeration Plant is the final report for the CEC/EPRI Agreement Number: CEC EPC-16-026 project conducted by the Electric Power Research Institute. The information from this project contributes to the Energy Research and Development Division's EPIC Program.

For more information about the Energy Research and Development Division, please visit the CEC's research website (www.energy.ca.gov/research/) or contact the CEC at ERDD@energy.ca.gov.

ABSTRACT

In California, reducing the state's carbon energy footprint with more intermittent renewable generation, and less predictable loads call for innovative ways to balance generation and loads. This project field tests one such approach—flexible demand response (DR)—at representative sites in two sectors: water pumping and industrial food refrigeration. These sectors are ideal for flexible DR because they store energy—as potential energy in water in storage tanks, and stored thermal energy in frozen food warehouses—that can be dispatched in response to a shortfall or excess in generation capacity.

At the water pumping site, station operators reliably reduced power demand for an extraction pump by approximately 30 percent, for up to four hours, without affecting the station's ability to serve its customers. Site management expressed enthusiasm for investigating broader application of flexible DR at additional sites. At the industrial refrigeration site, the team successfully achieved flexible DR on average at 25 percent of total baseline compressor demand by either increasing or decreasing demand for more than 12 hours. In addition to primary objectives, this project also demonstrated the effectiveness and reliability of the bi-directional OpenADR 2.0b standard, and identified additional on-site candidate loads for flexible DR, such as electric floor heaters and electric forklift truck chargers.

The team accumulated a wealth of knowledge and began its transfer through whitepapers, and interactions with stakeholders, utilities and a range of stakeholder communities in California. Technology transfer is also anticipated through direct interaction with service providers, such as systems integrators, software implementers, and DR aggregators. Flexible DR advancement will enable the California grid to accept more renewable energy, reduce the amount of solar curtailment occurring today, help maintain and enhance system reliability to lower energy costs, and better balance generation and load to capture avoided ancillary service costs. Moreover, economic benefits from additional revenue streams for water pumping and industrial refrigeration DR services could, at least partially, be passed on to California consumers, resulting in lower water service and food storage costs.

Keywords:
Flexible demand response, refrigeration, water pumping, OpenADR, renewable energy integration

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Background

California's aggressive actions to decarbonize its energy sector nationally and worldwide will result in a massive increase in utility-scale solar and wind generation in the state. Renewable energy is intermittent. At the same time, behind-the-meter generation, when power generating equipment is located on site, means that an increasing fraction of the load is less predictable than it has been historically. For decades, demand response (DR) has been one of the tools used by electricity grid operators to balance generation and load. Traditionally, DR has been used to reduce peak loads in response to unexpected high demand or drops in generation because of unforeseen component failures. As renewable generation increases, end-use loads such as lighting or cooling must be more flexible by reducing or increasing electricity consumption, sometimes at short notice, responding to this shortfall or excess of generation. This concept is referred to as "flexible DR."

The ideal candidates that are well suited for use of flexible DR have inherent and very accessible stored energy. For example, the water pumping sector, has a gravitational potential energy stored as water in large tanks located at an elevation high enough to supply water demand at an appropriate flow rate and pressure. For the industrial food refrigeration sector, stored thermal energy in a frozen room corresponds to the amount of heat that can be extracted from the food by making it colder. In both cases, increasing or decreasing the amount of stored energy is relatively simple: more or less water in the tanks, or higher or lower food temperature in the warehouse. Limitations of how much energy can be stored are imposed by the maximum capacity of the water tanks, or by the minimum temperature that is achievable by cold storage warehouse refrigeration equipment. There are also limitations in the rate at which stored energy can be accessed.

Both of these relatively homogonous sectors are good candidates to duplicate the developed strategies which can be used at multiple other sites with similar characteristics.

Project Purpose

This project developed and demonstrated integrated software control strategies to facilitate flexible DR adjustments at two sectors: a water pumping station, and an industrial food refrigeration warehouse. These sectors are ideal for flexible DR because they have built in inherent storage —in water storage in the water pumping and stored thermal mass in frozen and refrigerated food, that allows a temporary shed, shift or adjustment in power demand which are key enablers for fast and flexible demand response.

Challenges in implementing flexible DR include lack of awareness from industrial process operators regarding the grid need in relation to their operational capability to adjust power consumption . Challenges also stem from lack of a standardized methodology to apply available communications protocols to a specific process. The goal of this project was to demonstrate how a) the water pumping sector can use historical and real-time data to support decision-making by operators on viable strategies for participating in a DR event , and b) the commercial refrigeration sector can use existing process optimization tools to leveragethat can support a reliable adjustment in power consumption in response to a DR service provider signal. The project objective was to develop pilot test strategies to achieve at least a 20% demand adjustment and to advance industry understanding on best practices for engaging demand flexibility, whether through customer notification or utilizing load control. Implementation of this technology would benefit ratepayers by improving the ability of the California grid to integrate higher levels of intermittent renewables, while keeping or improving system reliability, lowering electricity costs, and reducing dependence on carbon-emitting resources.

Technology transfer from this research and pilot testing involved the advancement of understanding how DR can play a role in grid balancing, especially in relation to increasing renewable integration. The project provided pilot test results and best practice guides to inform how demand side resources can be leveraged for utility grid balancing and supply side resources for California Independent system Operator (CAISO) energy markets.

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Project Approach

The project team, led by the Electricity Power Research Institute (Palo Alto, California), selected a water pumping site and a commercial refrigeration site. The Tubeway Station 32, was the water pumping site for field testing and is operated by California Water Services (Cal Water), which is California's largest water distribution operator. Tubeway Station supplies water to the disadvantaged community of East Los Angeles Area, which is served by Southern California Edison (SCE). The industrial refrigeration test site was located in Mira Loma, California, and operated by Lineage Logistics, the world's largest operator of refrigeration.

For both sub-projects, the team developed and demonstrated a Flexible Energy Management System (FEMS). This provided the overall end-to-end architecture for facilitating data exchange, at the water pumping site and at the refrigerated warehouse. At the water pumping site, the team focused on forecasting DR capacity and engaging operators in the decision-making process leading up to participating in DR events. The project team developed a decision support tool to provide operators with key information, allowing them to quickly decide whether participating in a DR event would disrupt their operations. At the industrial refrigeration site, the emphasis was on end-to-end automation (testing the entire software) in a DR event and simulating the path of information from the DR signal dispatch to the plant automation system.

Two Technical Advisory Committees (TACs) were formed for each sub-project. The water TAC team was comprised of working at California ISO, Hawaiian Electric Company, Sacramento Muncipal Utility District, San Diego Gas and Electric Company (SDG&E), SCE, Sonoma County Water Agency (SCWA), and Inland Empire Utilities Agency (IEUA).

The refrigeration TAC included members working at SCE, Pacific Gas and Electric (PG&E), Southern Company, Lineage Logistics, NXTCOLD, Mayekawa, and M&M Refrigeration.

The TAC individuals both served as a sounding board as the project progressed, and provided assurance that the correct direction was being implemented. Emergence of the COVID-19 global pandemic in the final year of the project created some difficulties with in-person work at the host sites, but the project team was able to communicate in a timely and safe manner. Through the execution of a robust research plan, this project was able to characterize the performance, market barriers/drivers, and savings potential for the sites.

Project Results

The project successfully demonstrated that the FEMS was able to achieve the goal of adjusting power by at least 20 percent. Both the water pumping site and the refrigeration site were able to reduce their power demands.

At the water pumping site, the station operators, assisted by FEMS, were reliably able to reduce power demand for one of the extraction pumps by approximately 30 percent, for up to four hours, without affecting the station's ability to serve its customers. Moreover, the plant operators gained experience with forecasting tools, and communicated to the project team that this experience made them more receptive to future use of fully automated DR at their facilities. In addition, site management expressed enthusiasm for investigating broader application of flexible DR at additional water pumping sites, and also identified a pumping station that may be conducive to increasing consumption during times of power system overgeneration. Management suggested that the cloud-based data exchange architecture implemented for the Tubeway Station 32 test site could be readily leveraged to investigate flexible DR potential for additional Cal Water pumping station sites, given the scalable nature of the implemented FEMS architecture for data exchange with Cal Water's Water Management System.

At the industrial refrigeration site, the team successfully achieved flexible DR on average at 25 percent of total baseline compressor demand in both directions (powering up and powering down), by either increasing or decreasing demand during a DR event, for more than 12 hours. The team demonstrated the effectiveness and reliability of the bi-directional OpenADR 2.0b standard. The Open ADR 2.0b standard is a public domain communication protocol for pilot testing fast DR and select forms of flexible DR, such as balancing energy and ramping energy. OpenADR 2.0b supports advanced messaging features and has yet to be employed for fast and flexible DR at water pumps or at refrigeration facilities.

Moreover, although this was not a part of the agreement scope of work, the team identified additional loads at the refrigeration site that could increase the scope and effectiveness of the DR, such as electric floor heaters, and electric forklift truck chargers. The team tested floor heater DR and determined that floor heaters accounted for 722 kW, or 42 percent of the total average site load. However, the team decided that DR testing of the forklift trucks, without the aid of a charging scheduling software, would severely disrupt warehouse operations. Both floor heating and electric forklift charging could provide DR capacity that is essentially instantaneous and would complement the long duration but slower DR capacity provided by the refrigeration system.

The team identified critical components that are required for reproducing this system on a larger scale, including extracting and integrating historical information from databases for operator DR decision-making, using data to obtain forecasts of DR potential, training operators, and modeling of water distribution systems and refrigerated warehouses.

Advancing the Research to Market

From this project, the research team and its collaborators have accumulated a wealth of knowledge to share with stakeholder communities, especially plant operators, utility companies, electricity market operators, DR aggregators, systems integrators, as well as controls, optimization systems, and software providers.

Knowledge was shared with the utilities via its semi-annual advisory meetings, regular reports and technical updates, and targeted webinars. EPRI staff also participated in conferences such as American Council for an Energy-Efficient Economy (ACEEE), Institute of Electrical and Electronics Engineers (IEEE), American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE), and plan to publish in the associated conference proceedings. EPRI staff also plan to publish peer-reviewed articles in relevant literature, for example the *IEEE Transactions on Smart Grid*, *Energy*, *Applied Energy*, and the American Society of Heating, Refrigerating and Air-Conditioning Engineers *Journal*. Knowledge transfer will also occur through the established CEC channels, including fact sheets, webinars, and reports available to the public.

Through collaboration with the utility team members, it is anticipated that there will be further engagement in flexible DR studies for potential broader application across the refrigeration and water sectors. Technology transfer is also anticipated through direct interaction with service providers, such as systems integrators, software implementers, and DR aggregators.

Benefits to California

Benefits of flexible DR advancement in California are multi-faceted. More DR capacity means that the California grid can realize an improved acceptance of a corresponding amount of intermittent renewable energy. Moreover, water pumping, and refrigeration-based DR could reduce the amount of curtailment that is already occurring today, particularly curtailment of solar power during spring and fall. Augmenting flexible DR capacity supports the concept of maintaining and enhancing system reliability to lower energy costs. The estimated savings for participating in DR at a refrigeration facility average between $12,000 and $19,200 per year. For water pumping facilities, the team estimated a reduced cost of $10,000-$12,000 yearly. Economic benefits from additional revenue streams for water pumping and industrial refrigeration DR services could, at least partially, be passed on to the consumer, resulting in lower water service and food storage costs.

CHAPTER 1: Introduction

The Demand Response Challenge in California

As California leads the nation in developing clean, reliable, affordable energy, a key technical challenge is to balance electricity supply with customer demand, in the face of increased intermittent renewable resource generation and uncertainty in customer electricity demand resulting from "behind-the-meter" distributed resources (for example solar rooftop, battery storage, and flexible end-uses). The growing need for coordination of end-use demand to balance intermittent supply has been a driver for advancing demand response (DR), enabling technologies and two-way communications in smart grid applications.[1]

DR refers to a dynamic change in end users' electricity consumption that is aligned with grid system or market needs. DR is an important mechanism that can be used to maintain balance between electricity demand and supply for grid operations and the associated wholesale markets. As demand goes up, less efficient generators are called on to serve this demand. By reducing demand during these periods, the system and market can potentially avoid using less efficient generation resources to meet high demand. Advancing energy-efficient and grid responsive buildings is a goal of California's energy policies, programs, and mandates. Continued improvements in energy efficient and smart energy utilization translate into lower electricity usage and costs, lower greenhouse gas emissions, and reduced need for power plant construction. In these ways, smart and energy efficient electricity usage provides important benefits to the state of California and its ratepayers.

Also, under Senate Bill 100 (Author, Chapters, Statute) and other complementary laws, California is required to produce "clean" energy by 2045. The State's strategy is to increase the amount of renewable power generation, especially solar and wind. As such generation increases, so does the need to find end uses that can vary their demand to follow supply availability. Storage capacity inherent in certain industrial end uses can be leveraged to enable DR that can absorb the power generation intermittency.

Prior work has successfully standardized communication protocols, such as Open Automated Demand Response (OpenADR), for sending DR event signals to customers. However, there is no widely accepted standardized procedure for customers to inform aggregators, utilities, or grid operators about the capabilities of customer facilities' flexible and responsive demand.

Traditional DR can be characterized as "slow" in response time after event information is communicated with significant advance notification—usually a day or hours prior to an event. With increasing intermittent resource generation, there is a need for "fast and flexible DR,"

[1] A smart grid communicates various grid or market needs to customers, while customers are aggregated to provide grid operators ongoing updates on capabilities and flexibility of demand they can provide.

in which the response time is more rapid than traditional DR, with signals sent minutes to seconds before actuation of response. Fast and flexible DR may meet grid operator needs, such as for flexible ramping and real-time balancing energy, as well as frequency regulation services.

While most industrial and water sector processes consume energy, and could in principle vary the rate at which energy is consumed, some are particularly well-suited for DR because they inherently store energy in a very accessible way (for example in the form of thermal or potential energy). Two such industrial-scale loads are addressed in this project: potable water pumping, and industrial food refrigeration. Both have built-in inherent storage: water storage in the case of water pumping, and thermal mass in the case of frozen and refrigerated food. This inherent storage enables temporary shedding, shifting, or adjustment of power demand, which are key enablers for fast and flexible DR.

In the case of water pumping, energy storage is in the form of water stored in large tanks located at an elevation sufficiently high that the potential energy of the water can be used to supply demand at an appropriate flow rate and pressure. In the case of industrial food refrigeration, stored energy is proportional to how much colder a mass of food is from its equilibrium state, namely ambient temperature. In both cases, increasing or decreasing the amount of stored energy is relatively simple: more or less water in the tanks, or higher or lower food temperature in the warehouse. Limitations in how much energy can be stored are imposed by the maximum capacity of the water tanks, or by the minimum temperature that is achievable by cold storage warehouse refrigeration equipment.

There are also limitations in the rate at which stored energy can be accessed. For the case of water pumping, when a pump is running at full capacity, it cannot consume more power. Similarly, if a pump is off, it cannot consume any less power. Analogous considerations apply for refrigeration equipment. However, most of the time, water pumping and food refrigeration equipment operate well within power and energy constraints, providing an opportunity to either reduce or increase load in response to DR signals.

Why Ratepayers Should Care

Effective DR can benefit California ratepayers in the following ways:

- **Enhanced Reliability**. Peak load reduction supports enhanced electric service reliability for electric ratepayers.
- **Keeping Rates Low**. When water plants better engage in DR, they can reduce their electricity costs and earn additional revenue streams from DR program and market participation. This enables water service providers to keep rates low, which translates into maintaining lower costs to water customers, who are often also electricity ratepayers.
- **Lower Refrigerated Product Costs**. Similarly, consumers of refrigerated products also benefit from lower product costs when cold storage facilities are able to earn additional revenue streams from participation in fast and flexible DR, and lower overall plant electricity costs.

- **Enhanced Safety**. The ability to automate demand reductions leads to increased safety of utility workers and the public. This can be done because lower throughput and demand on generation plants reduces wear and tear on equipment, and in turn helps to extend the life of equipment and reduce risk of equipment issues that could pose safety problems.

The Research Context: Why the Research is Needed

An important challenge is that process control systems in the water and industrial refrigeration sectors are built and managed by vendors with no incentive to support DR. In addition, water and industrial refrigeration customers are not creating sufficient market pull to add DR-enabling features to their control systems. To help address these challenges, research is needed to support development of software interfaces capable of communicating DR requests. The creation and demonstration of tools for load management best practices can enable an increased DR base across a broad range of plant sites, supporting electric system reliability.

One challenge is that current plant management systems are at best employed for interruption based on advance notification (such as day-ahead to hours-ahead). Legacy distribution-connected industrial refrigeration or water management systems are generally not deployed to satisfy rapid response requirements in markets such as non-spinning and spinning reserves, nor to provide flexible services such as 5-minute balancing energy.

Another challenge is that existing plant management systems controls lack the ability to offer advanced predictive capabilities. As a result, traditional DR programs require customers to pre-program static DR strategies in a dynamic operational environment that relies heavily on customer demand. To meet the faster ramping and response requirements of emerging programs seeking flexible DR, static pre-programmed control strategies will not suffice.

CHAPTER 2: Project Purpose and Approach

This section describes the project purposes, key audiences, project team, technical advisory committees, project challenges and how they were overcome, technical approach, field test sites, and key components of the sites.

Project Purposes

Following are the project objectives:

- To develop and test control strategies for flexible DR in water delivery and refrigerated warehouses.
- To develop and test control strategies that can achieve at least 20 percent demand reduction or adjustment.
- To develop a market signaling interface using OpenADR 2.0 to communicate fast DR and flexible DR event information.
- To advance industry understanding of best practices for employing load control in targeted plant types.

Moreover, for refrigeration systems, the project aims to develop advanced, data-driven predictive load management algorithms, which will consider the following:

- The operating ranges of the equipment.
- Boundary limitations of the customer's operational procedures.
- Equipment performance characteristics.
- Data from power monitors or sensors.

Audiences and Who Will Use This Research

The audiences and intended users of this research are:

- Utility customers, including owner/operators of water pumping stations and industrial refrigeration facilities.
- Grid operators of independent system operators (ISOs), utilities, and DR aggregators.

Utility Customers: Water Pumping and Industrial Refrigeration Owner/Operators

The project helps water pumping stations and industrial refrigeration owner/operators understand additional functionality beyond what is available in the water and energy management systems in their plants. The project also supports the decision-making of water and energy management supervisors and operators to engage in DR. The project helps these stakeholders assessing the feasibility of distinct DR strategies given forecasted demand, supply, and operating constraints, while providing these personnel practical hands-on experience in the DR decision-making process.

Grid Operators, Utilities, and DR Aggregators

The project advances an understanding of how to inform grid operators, utilities, and DR aggregators about the capability and availability of demand-side resources (such as water pumping and refrigerated facilities). The outcome of the research advances the ability and understanding of how water pumps and refrigerated facilities can play larger roles in grid balancing, especially for renewable integration. The project provides field test results and best practice guides to inform how demand-side resources can be leveraged to participate as a supply-side resource in the California Independent System Operator (California ISO) energy markets as defined by the California Public Utility Commission (CPUC) bifurcation framework[2]. The technology characterization framework, customer value, system value, and baseline DR data developed in the project can be used to advance the state-of-the-art in DR resource benchmarking
and targeting.

The Project Team

Each project team consisted of EPRI, the the overall project manager, host facilities, and supporting technology providers. The water pumping site was located at the Tubeway Station 32 and operated by California Water Service (Cal Water). Key technology providers for the water pumping project include CPower and Aqua Sierra Control. CPower provided DR aggregation perspectives and price forecasting expertise to inform conceptualizations of a novel Track and Trending tool described in Appendix J. Aqua Sierra Control served as systems integrator to augment Cal Water's existing water management system by adding power instrumentation for the pilot station pumps and additional measurement points

The refrigeration plant site is located in Mira Loma, California operated by Lineage Logistics. Key technology providers for the refrigeration project include CrossnoKaye, Inc., and Melrok.

CrossnoKaye, Inc., helped the team implement an API to translate incoming signals from MelRok into setpoint schedules for equipment controllers at the Lineage plant. They implemented a system to provide feedback information to the MelRok Virtual End Node. CrossnoKaye also helped the team with information on the architecture and algorithms used for optimal "flywheeling" controls, and with general information on the nature of the refrigeration system at the Lineage plant.

Melrok helped the team host the OpenADR Virtual End Node, and implement the translation of the OpenADR signals incoming from the EPRI Virtual Top Node. Melrok also worked with CrossnoKaye to implement an API to translate OpenADR signals to custom signals for the CrossnoKaye optimization system, and to translate feedback information from CrossnoKaye monitoring to OpenADR.

Both facilities are located in the Southern California Edison (SEC) service territory.

[2] In this context, DR is either a supply resource that participates in the California ISO market or a load modifying resource that reshapes the load curve (per a California ISO memorandum on September 11, 2014).

Technical Advisory Committees

The project team formed two Technical Advisory Committees (TACs)—one for water pumping, and one for industrial refrigeration. Each of the TACs provided advice to EPRI on any issues in the project activities, suggest actions for successful implementation, and advise EPRI on technology transfer.

The following are the members of the water TAC: Jill Powers and Peter Klauer, California ISO; Yoh Kawanami, Hawaiian Electric Company; Josh Rasin, Sacramento Muncipal Utility District; Kate Zeng, San Diego Gas and Electric Company; Dave Rivers, Southern California Edison; D. Roberts of SCWA; and P. Cambiaso of IEUA.

The following are the members of the refrigeration TAC: Paul Delaney, SCE; Christian Weber, PG&E; Kate Zeng, SDG&E; Pradeep Vitta, Southern Company; John Dittrick and Alex Zhang of Lineage Logistics; John Scherer, NXTCOLD; Troy Davis, Mayekawa; and Paul Valentine and Hank McConnell, M&M Refrigeration.

Both TACs provided very useful feedback to the project team, as related to project execution strategies. For example, the refrigeration TAC provided feedback that resulted in EPRI changing the field test site from an earlier site (in Long Beach) to an alternate site (in Mira Loma), due to system controller issues at the originally identified site.

Barriers and Challenges Overcome

Water Pumping Project

The project overcame several project challenges.

- **Data exchange architecture and security**. The team needed to devise an acceptable data exchange architecture with network security. To address this, the team engaged with water agency IT personnel to review workable data exchange methods, and then secured water agency permission for a cloud architecture for data exchange.
- **Water system model**. The team needed to develop a sufficiently accurate yet simple water system model and implement water SCADA system extensions. To address this, the team modeled the water system and identified existing SCADA points being instrumented from the field, before also instrumenting power usage of individual pumps at the pilot station as needed.
- **Demand forecast and water age**. The team needed to develop a water demand forecast and model a model a critical-water-age constraint that governs operations in Cal Water's applicable water zone. in Cal Water's applicable water zone. To address this, the team estimated water demand (such as monthly average load profile, and previous day data), and then modeled tank water age and implemented it as a constraint.
- **Missing and bad data**. The team needed to handle missing data and interpret bad data. To address this, the team identified data gaps and interpreted negative data values (for example negative tank levels, negative flow).

Refrigeration Project

The project overcame the following project challenges:

- **Initial site complexities**. The team encountered complexities with the energy optimization system at the initial identified field test site. To address this, in consultation with the TAC, the team changed sites to a site with a more compatible energy optimization system.
- **Plant operation and loads**. The team needed to understand complex industrial refrigeration plant operation and loads. To address this, the team identified major loads within the refrigeration plant, and scoped potential flexible loads. The team then worked together to gain an understanding of the complexities of the site's compressor system.
- **DR event complexities**. The team encountered complexity of executing DR events. To address this, the team determined a way to seamlessly send and receive DR signals, and worked with on-site personnel to implement DR on compressor systems and floor heaters without disrupting operations.
- **Asymmetric DR**. The team experienced asymmetric DR in initial field tests (specifically obtaining "power-up" response was much easier than obtaining "power-down" response). To address this, the team developed a simplified thermal model (described in Appendix H) that describes the main features of the dynamic interaction between the compressors-evaporators, the air and food in the frozen rooms, and the frozen room envelope. The model revealed important features of the heat transfer processes. Based on these insights, the team designed an improved procedure and implemented it in a new set of experiments.

Technical Approach

The project used a structured step-by-step method for developing control strategies:

- **Developed a categorization of pump and refrigeration load control**. The project team developed a categorization that provides context for pump and refrigeration control for different plant types, pump types, equipment capabilities, and operating flexibility scenarios.
- **Developed control strategies for water and industrial refrigeration**. The project team researched and developed control strategies appropriate for each pump and refrigeration load in the respective end-use sectors. The team refined control strategies based on operational constraints and operator acceptance of pump controls and refrigeration controls.
- **Tested the developed control strategies**. The project team tested the developed control strategies in a controlled test environment, followed by real-world customer field test sites to evaluate demand adjustability potential. The team implemented a FEMS to provide DR and other critical information needed to engage participants in DR. FEMS integrates electricity use with process information (such as water flow rates and storage levels in the water sector; product temperature in the refrigeration sector), available through SCADA systems, to support operator decision-making on strategies for controlling pumps or refrigeration units to support DR.

- **Used a context-based approach**. The project team aimed to develop control strategies that are broadly applicable across multiple customer sectors. To do so, the team developed context-appropriate control strategies, supportive of real-world conditions that plant operators face. Through the initial development of structured categorizations for pump and refrigeration control, the project produced control strategies that are applicable across different pump technology types (for example centrifugal, vertical, well, booster, etc.), as well as different power usage adjustment capabilities (such as on/off, speed adjustment). This approach helps to ensure broad and ongoing applicability of project findings for a range of plant types, pumping purposes, and storage contexts.

The team also used the following approaches:

- **Leveraged existing equipment and plant SCADA systems**. The project leveraged existing SCADA monitoring systems by interfacing with the data they provide to control existing plant equipment (for example variable speed pumps and refrigeration units). This enables rapid and cost-effective advancement of learnings.
- **Used an open standard for information exchange**. OpenADR is an open, two-way information exchange model and global Smart Grid standard that has been in use since 2009. For the refrigeration field test, the project team used the OpenADR 2.0b communications protocol for field testing fast DR and select forms of flexible DR, such as balancing energy and ramping energy. Although OpenADR 2.0a has been widely employed for DR signaling, OpenADR 2.0b supports advanced messaging features, and has yet to be employed by water pumping or refrigeration facilities to enable fast and flexible DR. This project was among the first to field test the technology for industrial refrigeration.
- **Used integration software and displays**. The project technique developed integration software (FEMS) and operator displays, where critical gaps existed in plant control technology for fast and flexible DR, to share these developments broadly across the SCADA systems integration community.
- **Conducted measurement and verification (M&V).** M&V involved obtaining the detailed data needed to support fast and flexible DR implementation and to determine load shape impacts. To conduct M&V, at each field test site, the project team:
    1. Constructed baseline data using interval data collected at the site and/or affected devices on days that may be considered similar to the days of called interruptions.
    2. Developed flexible interruptible strategies for which the baseline load shapes and the treatment load shapes were constructed.
    3. Used test events for each control strategy and for each season in order to quantify DR performance.

Appendix C contains more information on the novel developments and standards used in this project.

Water Pumping Site, Water System, and Tool Innovation

The DR Opportunity

Flexible DR opportunities in water pumping reside primarily with pumping equipment in the water and wastewater sectors. Appendix A outlines a taxonomy for identify DR strategies in the water and wastewater sectors. The described taxonomy enables systematic identification of pumping equipment in different plant or station types to consider in flexible pumping strategies.

- In particular, in the water sector, extraction pumping and conveyance pumping are potential candidates for adjusting speed of pumping operation to provide DR.
- In the wastewater sector, influent and effluent pumps present opportunities for flexible wastewater pumping, especially in stations with redundancy in pumping equipment and/or ample wastewater storage capacity.

For constant-speed pumps, a strategy is to turn on/off pumps in coordination with system or market needs. For variable-speed pumps, strategies include adjusting pumping speed, based on available speed settings configured for the pump that are accessible by the water or wastewater management system.

Field Test Site

The water pumping station is known as Tubeway Station by its operator California Water Services (Cal Water). The station uses an elevated storage tank system fed by various pumps. Figure 2-1 depicts the tank and variable-speed pump housed within a pump shelter, the building that houses controls equipment and electrical panels, and an elevated storage tank.

Figure 2-1: Cal Water Tubeway Station 32 Pumping Equipment

A variable-speed pump, shelters for pump/controls, and a storage tank at Tubeway Station 32

Source: Cal Water

Water System Description

Cal Water is one of the largest water utilities in the United States and the largest in California, with a total pumping capacity of 500,000 GPM and a corresponding electricity demand of 40 MW. Cal Water serves more than two million customers, operating a system consisting of more than 6,000 miles of main pipeline, 1,130 wells, 662 water storage tanks, more than 155,000 valves, 50,000 hydrants, 2,010 sampling stations, six surface water treatment plants, and 11 wastewater treatment plants.

The portion of the Cal Water system that is modeled in this project is referred to as Zone D. Shown schematically in Figure 2-2, Zone D is representative of a typical sub-component of the

Cal Water system. Zone D has a total pumping capacity of 20,000 GPM, with an associated peak demand of 1.6 MW. Tubeway Station's peak DR capacity is 300 kW, or about 19% of the Zone D peak demand.[3]

Zone D includes three connected storage tanks at station #040, additional tanks at stations #055 and #010, two booster pumps at station #058, eight aggregate supply pumps that extract groundwater, one pump and tank at station #023, and two variable-speed pumps at station #032 (Tubeway Station). For the purposes of this project, Tubeway Station was engaged in DR with one of its variable-capacity pumps, namely pump 6201.

Water System Components and Operation

To understand how different components in a water pumping system can be leveraged to play a role in load flexibility, it is useful to understand the multiple roles that each component plays in the operation of the system. [4]

Various components in a water system draw electrical power demand. Water pumping is the principal source of power draw in the system. Figure 2-2 shows that the principal components of the water system include storage tanks, pumps, and the water treatment.

- **The storage tanks**, located at higher elevation than demand they serve, provide throughput to deal with rapid changes in demand by maintaining constant pressure, deal with unplanned power loss (of up to 4-hour duration) leading to pump inoperability, and provide water to fire services.
- **The pumps** extract water from groundwater resources, help maintain system pressure, and/or move water to different parts of the system.
- **Water treatment** equipment is installed at each pump location, including Tubeway.

Cal Water practices three different types of treatment:

- Removal of iron and manganese ions
- Removal of volatile organic compounds (VOCs)
- Addition of Chlorine (Cl) and Ammonia (NH3) to form Chloramine (NH2Cl), which is a stable compound that keeps water safe to use and drink as it travels through the distribution system to the customer

4. Source: https://www.calwater.com

3

https://www.calwater.com

4

Figure 2-2: Cal Water Zone System

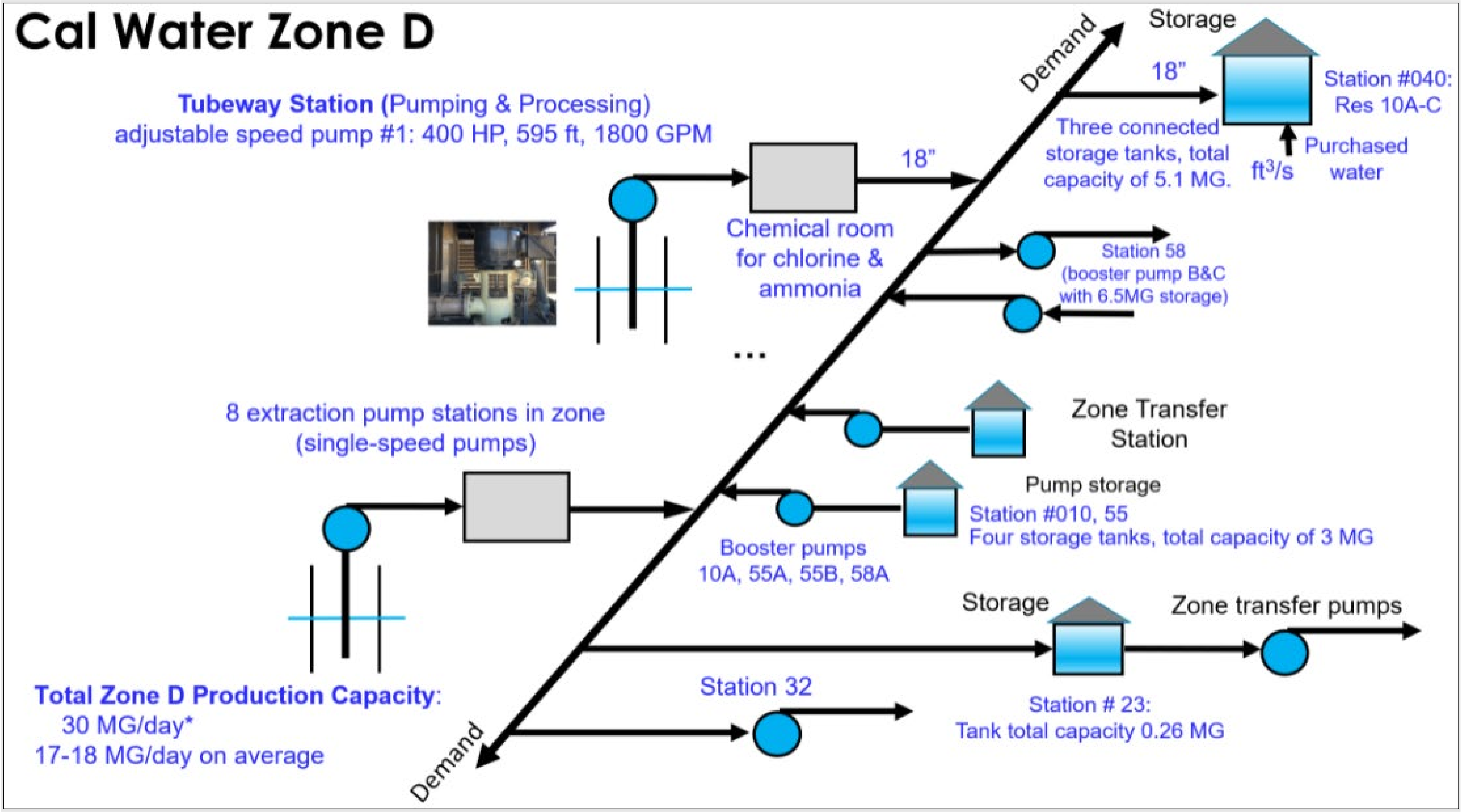


Diagram showing Cal Water zone D system

Source: EPRI

Older water extraction pumps are either on or off. Newer installations, such as the two pumps located at the Cal Water Tubeway Station (the site of this project), are powered by variable frequency drives (VFDs). The variable-speed pumps provide the system with the ability to adapt to variable demand easily without the need for the large number of start/stops of single-speed pumps. Although the VFD makes it possible to vary the speed of the pump continuously from 0 percent to 100 percent of rated capacity, in reality Cal Water uses three predefined speed settings. These pre-defined speed settings are matched with similarly pre-defined water treatment equipment settings, which are simpler and more reliable than the feedback system that would be required by continuous operation.

Water is transferred between adjacent zones to make up for capacity in a given zone at certain times. Generally, operators run the system to satisfy customer demand while minimizing total cost by balancing the cost of pumping with the cost of purchased water. In some cases, it is less expensive to pump water either sourced locally or from adjacent zones, but in other cases (such as in the case of high energy cost or high system demand), purchasing water may be more economical. While energy costs are considered in the day-to-day operation of the Cal Water system, to date these have not been the primary focus. Instead, Cal Water chooses to provide reliable, resilient, and high-quality service to its customers. This is also a result of Cal Water's ability to pass energy costs to the customer directly. In future operations, this may no longer be the case, and energy costs will therefore become more significant in plant operating decisions.

Industrial Refrigeration Site, Loads, and Control System

The DR Opportunity

Refrigerated warehouses can potentially provide similar operating characteristics as a battery energy storage system, with energy discharge in the form of load curtailment and energy charging in the form of increasing refrigeration power loads. In a sense, a refrigerated warehouse is a thermal battery energy storage system that stores energy in the form of frozen products. Industrial refrigerated warehouses exhibit a unique combination of factors that are favorable for DR, such as:

- They consume a substantial amount of electricity.
- Refrigeration loads account for a sizeable portion of the facilities' total energy usage.
- Their usage is often greatest during utility peak periods.
- The thermal mass of the stored product in the insulated spaces can often tolerate reduced cooling capacity for a few hours when needed.
- This same thermal mass can also consume surplus grid capacity when events of over-generation occur during the spring and fall and the warehouse is below its peak capacity at mild ambient conditions.
- System DR capability is fast and flexible, potentially increasing or decreasing power several times a day and doing this relatively quickly.

Appendix B contains more information on DR opportunities at refrigerated facilities in California.

Field Test Site

Located in the Southern California Edison (SCE) service territory, the industrial refrigeration demonstration site is owned and operated by Lineage Logistics, which is one of the largest food distribution warehouse companies in the world. The project's test facility is located at 3251 De Forest Circle in Mira Loma, California. Figure 2-3 provides an aerial view of the plant. It is in the CalEnviroScreen 3.0 Percentile of 85 percent-90 percent [1]. For more information on the plant, the Lineage website provides the details [2].

Figure 2-3: Lineage Industrial Refrigeration Site

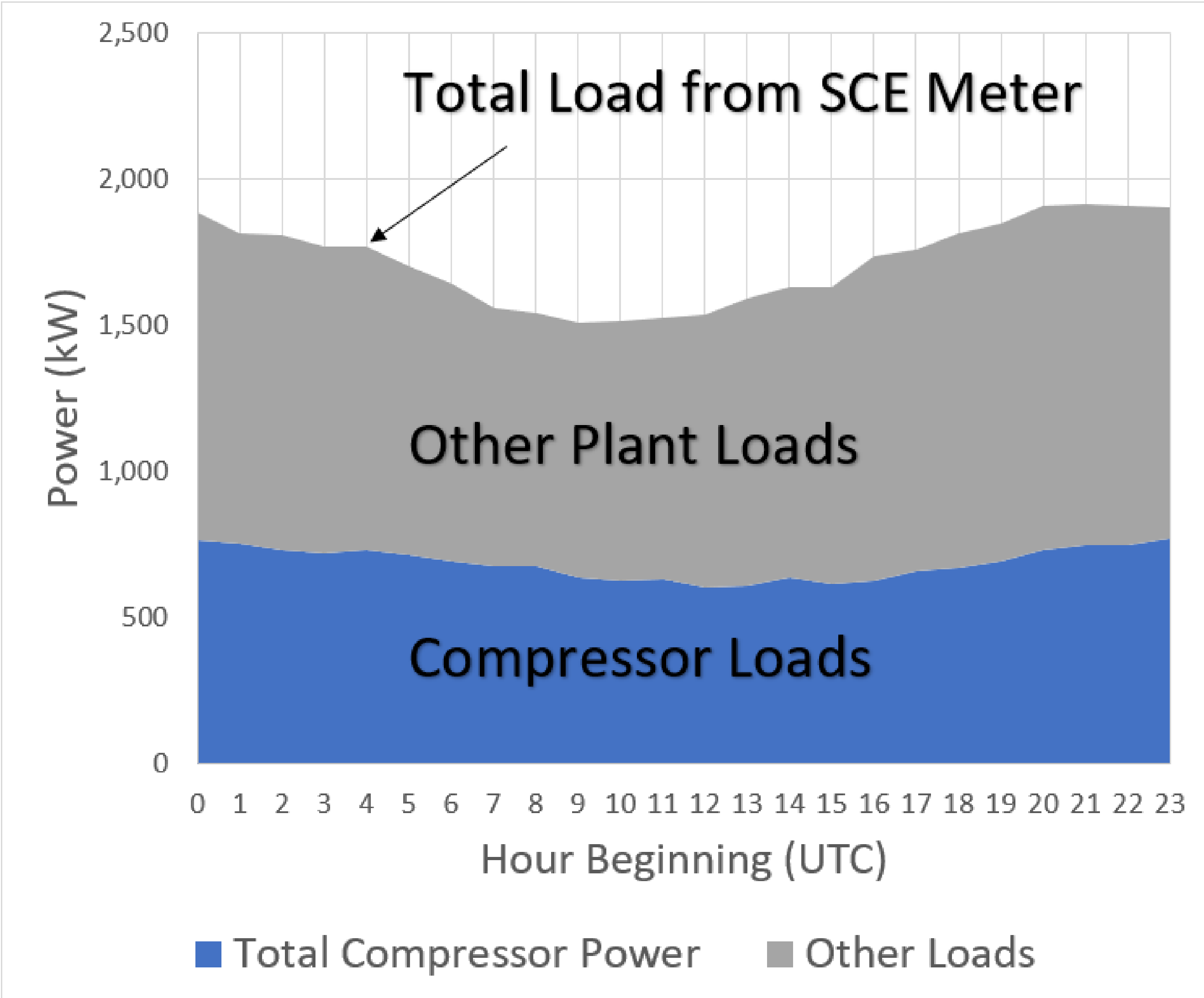
Overhead view of Lineage refrigeration site

Source: [Lineage Logistics](https://www.lineagelogistics.com/facilities/mira-loma) (https://www.lineagelogistics.com/facilities/mira-loma)

Refrigeration Site Loads

The refrigeration plant, in the SCE service territory, is a direct access customer, served by Calpine as the energy service provider. It uses a time-of-use (TOU) and demand rate structure. The plant's power demand is around 2.6 MW, and its electricity bill is approximately $2.2 million. Figure 2-4 shows the fluctuation of hourly loads at the plant for a typical day during testing, taking the average daily data from October 17, 2020, to December 28, 2020.

Figure 2-4: Average Daily Load of Refrigeration Site



Typical hourly load fluctuation at the Lineage industrial refrigeration site

Source: EPRI

The Lineage plant is a traditional refrigerated warehouse with a central system using ammonia refrigeration to cool an area of about 700,000 square feet (65,000 square meters), separated into 11 rooms. The cold spaces range in temperature as follows:

- Freezer rooms (less than 0°F, -18°C).
- Cooler rooms (0 to 32°F, -18°C to 0°C).
- Dry storage area (more than 32°F/0°C).
- Dock areas (40°F, 4°C).

At the refrigeration site, the largest individual load type was the compressor loads, at approximately 40 percent. However, the team identified other significant loads:

- **Electric Floor Heating.** Floor heating on the site was another significant load identified during this research project. Floor heating is required in order to keep the ground stable in freezer rooms that operate at very low temperatures. At the test facility, the floor heaters are electric resistance strip heaters; these prevent ice formation in the soil below the slab/foundation. This in turn helps prevent floor buckling, which is dangerous to the building and operations (such as forklifts need level ground to operate safely). At the Lineage refrigeration site, 9 out of the 10 rooms had electric resistance strip floor heaters installed. Each room had a varying number of floor heaters, with 353 floor heaters installed across the site. At the test facility, rooms 4, 5, and 7 had an automated system where DR controls could be implemented. Although all floor heaters are not operated coincidently, the total rated power of all floor heaters was 722 kW, or 42 percent of the total average site load. Because the floor heaters are capable of instantaneous response (a desirable feature for fast and flexible DR), a DR event was investigated for rooms 4, 5, and 7 during this project.
- **Electric Forklift Trucks.** A fleet of approximately 100 on-site electric forklift trucks used 105 chargers installed within the plant, with power ratings ranging from 3.6 kW to 10.5 kW. Although all of these chargers are not used at the same time, the total rated power of all electric forklift chargers was 678 kW, or 39 percent of the total average site load. Currently, charging of the forklift trucks occurs on an as-needed basis: when a specific forklift truck reaches a minimum state of charge, the operator using it connects it to a charging station and picks up another truck. To some extent, charging schedules are associate with shifts, although there is currently no charging schedule optimization. Implementing DR in the context of existing operations could result in unacceptable disruption. However, charging loads may be a potential source of DR in the future with additional monitoring and optimization.

Control System Used in the Refrigeration DR Sub-project

The Lineage refrigerated warehouse at Mira Loma, California, is a large plant first commissioned in the 1980s, and is representative of many similar plants statewide and nationwide. In recent years, since the acquisition by Lineage, the plant has received several efficiency upgrades including, notably, variable-speed drives on several of the ammonia compressor motors. Operation of the plant refrigeration system is based on controlling temperature. Specifically, proportional-integral-derivative (PID) controllers track temperature by adjusting the fan speed of evaporators located in each room to provide varying amounts of heat removal. In turn, the refrigerant (ammonia) return temperature at the exit of the evaporator coils is monitored to control the refrigerant flow rate and hence the compressor speed and associated electric power draw. The significance of this, for the purposes of this project, is that adjusting the temperature setpoint of individual rooms is the mechanism by which compressor electrical load can be adjusted to provide DR.

Adjustment of the temperature setpoints to control power consumption is not new at this plant. The same mechanism is used in a process commonly known as "flywheeling," whereby compressor power is adjusted in response to hourly, daily, or weekly forecasts of energy unit cost. When energy cost is low, compressor power is increased, and vice-versa. The thermal capacity of the frozen food serves as energy storage. While this mechanism appears simple, adjusting power demand to minimize energy cost while ensuring that food temperature is maintained within limits set out by the warehouse customers is in reality a complex optimization process. Optimal scheduling of the temperature setpoints is provided by CrossnoKaye, a company that specializes in refrigerated warehouse energy system optimization. Appendix C contains details of the CrossnoKaye optimization service.

The control configuration at the Mira Loma plant provided an excellent starting point for implementing the DR demonstration in the refrigeration sub-project. Specifically, to enact DR, it is necessary to adjust the temperature setpoint of one or more rooms—upward to reduce load, and down to increase load. Moreover, the requirement was to use the OpenADR 2.0b protocol to adjust the temperature setpoint, and to monitor the response of the plant to the DR signal.

The high-level architecture of the refrigeration plant DR reflects the need for the system to be broadly applicable. For example, it should be able to use legacy system energy management and/or optimization services (CrossnoKaye is used in this project) that may not be able to receive or send OpenADR communications, and different intermediary OpenADR-enabled virtual end nodes (MelRok is used in this project) that translates OpenADR into a data stream that can be used by the legacy system. Figure 2-5 shows this high-level architecture, including the EPRI virtual top node (VTN).

Figure 2-5: High-Level Architecture of OpenADR Implementation

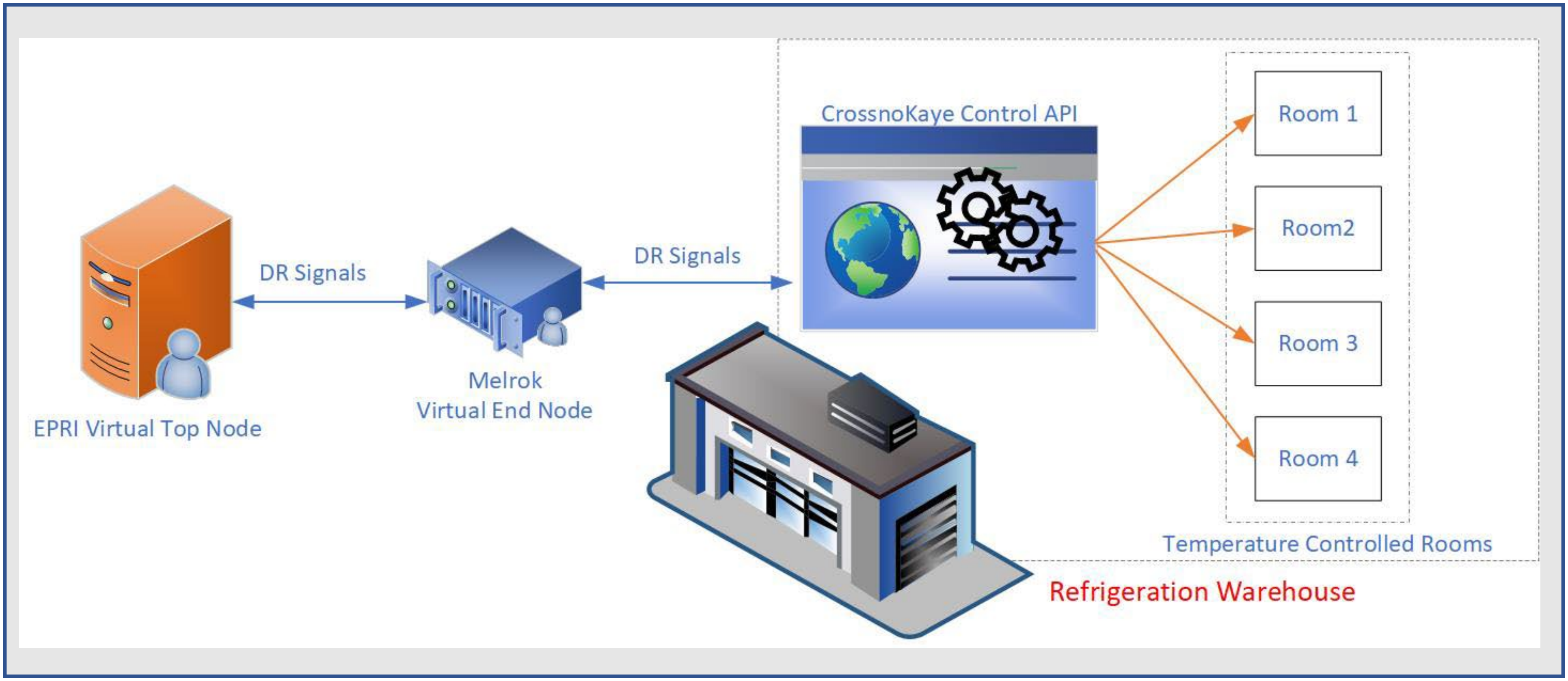


Diagram of implementing OpenADR 2.0b on the Lineage refrigeration plant with process optimization

Source: EPRI

Figure 2-6 details the communication architecture that was developed for the project. The architecture leverages new capability in the OpenADR 2.0b protocol and uses an intermediary (MelRok) to translate OpenADR 2.0b messages to the CrossnoKaye scheduling optimization system, which is not configured to receive or send OpenADR communications. The use of the MelRok Intermediary gives the architecture a high degree of flexibility, by allowing legacy systems to interact with the outside world via OpenADR 2.0b. In turn, OpenADR 2.0b is of interest to the utility industry because it allows standardization (and thus, higher adoption), while allowing higher flexibility in relaying information (for example by allowing direct reporting of the outcomes of a DR signal). Using this architecture, EPRI uses VTN to issue a DR notification, which includes information on power level requested and duration via an OpenADR 2.0b message. The message is received by MelRok, and its contents are relayed to CrossnoKaye via a custom API. CrossnoKaye uses the received information to produce a temperature setpoint schedule and delivers this schedule to the plant controls via an internet-of-things (IoT) server. Submetering information at the plant is accessed by CrossnoKaye and sent to MelRok via the custom API. MelRok interprets the information, and reports this to the VTN at regular intervals.

OpenADR 2.0b also allows features of interest in the context of fast and flexible DR, including the ability to characterize DR potential via analysis of data obtained via its reporting features. Appendix D provides more detail on the sequence of events that take place during a DR event, following a DR signal.

Figure 2-6: Communication Architecture for OpenADR Implementation

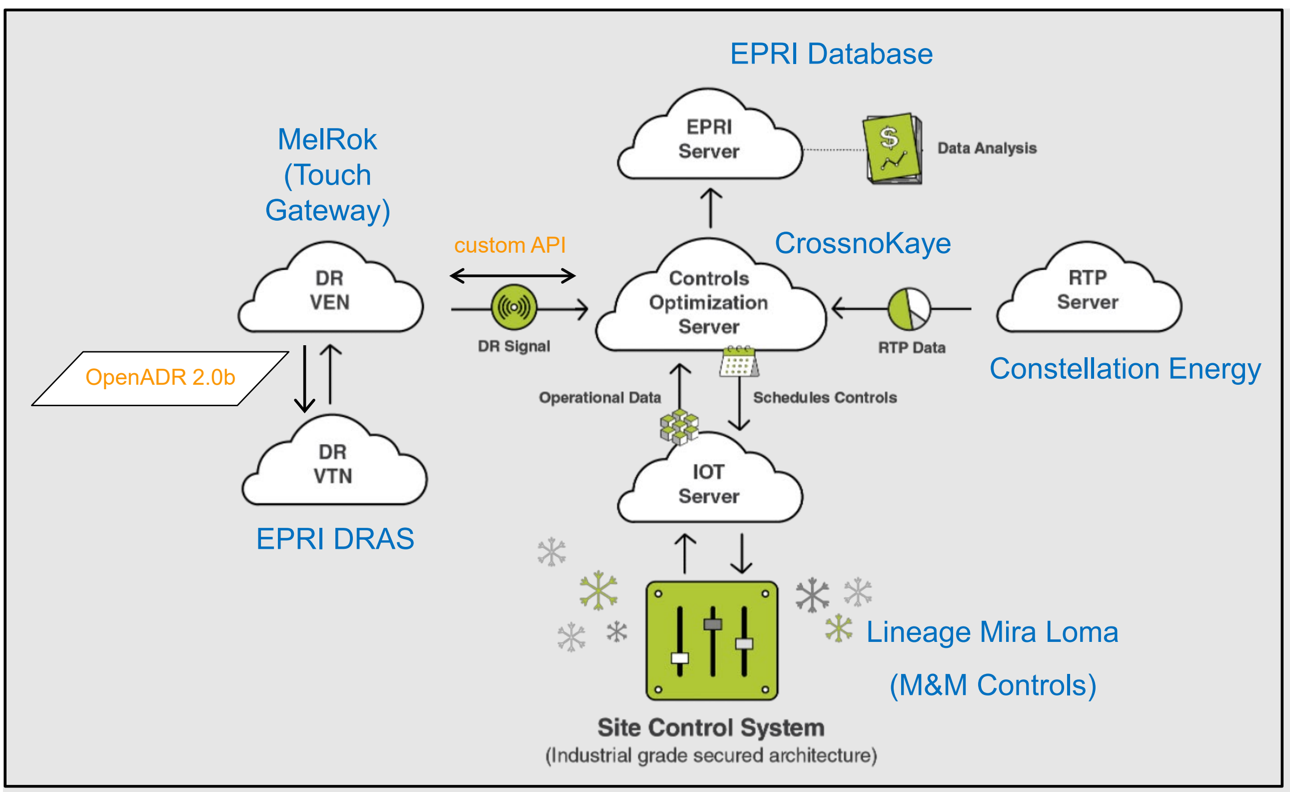


Diagram for implementing OpenADR 2.0b on the Lineage refrigeration plant with process optimization

Source: EPRI

CHAPTER 3: Project Results: Water Pumping Plant

DR Engagement

Day-Ahead Supervisor

The day-ahead screen enables the supervisor to explore operation strategies and simulate the outcomes. The supervisor then uses this information to decide whether they will provisionally opt into the DR event the next day. If they choose to opt in, their strategy for the next day will be saved. The process for decision making starts with a DR notification the day before the DR event, delivered via email. The notification prompts the supervisor to view the decision support tool via web browser. Supervisors are able to adjust flowrates, via pump settings, to react to changing circumstance, or as in the present case, to opt into a DR event.

Day-of Operator

On the day of the DR event, the operator receives a DR alert about four hours before the DR event, via email. The values in the decision support tool are updated with the latest information on zone D, and the supervisor can update their decision to opt in based on the newest information. If the system's constraints are not met with the previous day's operational strategy, the supervisor may need to update their operation plan before opting in, or alternatively opt out of the event. During the DR event, the supervisor then follows their operational strategy to ensure no constraints are broken as a result of the DR event.

Field Test Period

Nine DR test events were scheduled between May 12, 2021, and June 1, 2021. Through field testing, the opt-in and opt-out decisions of the supervisors and operators were recorded, along with the power demand of the Tubeway Station pump engaged in DR testing. Actual power consumption was measured and analyzed for Tubeway Station's Pump No. 6201 shortly before, during, and shortly after each of nine DR events.

The DR event periods constructed by the project team attempted to replicate realistic conditions that a demand-responsive customer encountered while operating within the California grid. The events occurred on weekdays between 4:00 p.m. and 9:00 p.m., with a duration of two to four hours.

For each DR event, a day-ahead notification was sent to Cal Water operations. Cal Water then reviewed the day-ahead screen on the flexible water pumping decision support tool to determine whether it would be feasible to opt into the DR event the next day, based on various operational constraints. When a Cal Water system supervisor provisionally decides to opt in, the operational strategy for the next day is saved. On the day of the DR event, the Cal Water operations team reviews the day-of screen of the decision support tool to monitor progress of its decision to opt into the DR event occurring that day, or otherwise decides to override the decision.

Baseline and Treatment Periods

The main findings for the field test consist of the power reduction achieved by the designated 6201 variable-speed pump located at Tubeway Station during DR event periods. Since overall water demand over time is the same regardless of whether there is a DR event, no long-term energy savings are expected from the reduction in pump energy during DR events; the energy use is merely shifted to a different time. Table 3-1 summarizes the outcomes of DR events in this field test.

Table 3-1: Pump 6201 DR Power Reduction Results

DR Event Date	Time	Average Power Reduction over DR Event Compared to 10-in-10 Baseline (kW)	Percent Reduction from 10-in-10 Baseline
May 12, 2021	4 to 6 p.m.	79	31%
May 18, 2021*	4 to 6 p.m.	NA	NA
May 25, 2021	4 to 6 p.m.	84	32%
May 27, 2021	4 to 7 p.m.	84	32%
June 2, 2021	4 to 7 p.m.	83	32%
June 4, 2021	4 to 8 p.m.	83	31%
June 8, 2021	5 to 7 p.m.	81	31%
June 10, 2021**	5 to 8 p.m.	55	21%
June 17, 2021	5 to 9 p.m.	82	31%

* Because pump 6202 power was accidentally reduced instead of pump 6201, this event is excluded from calculations.

** Pump power was accidentally increased one hour before DR event conclusion.

Source: EPRI

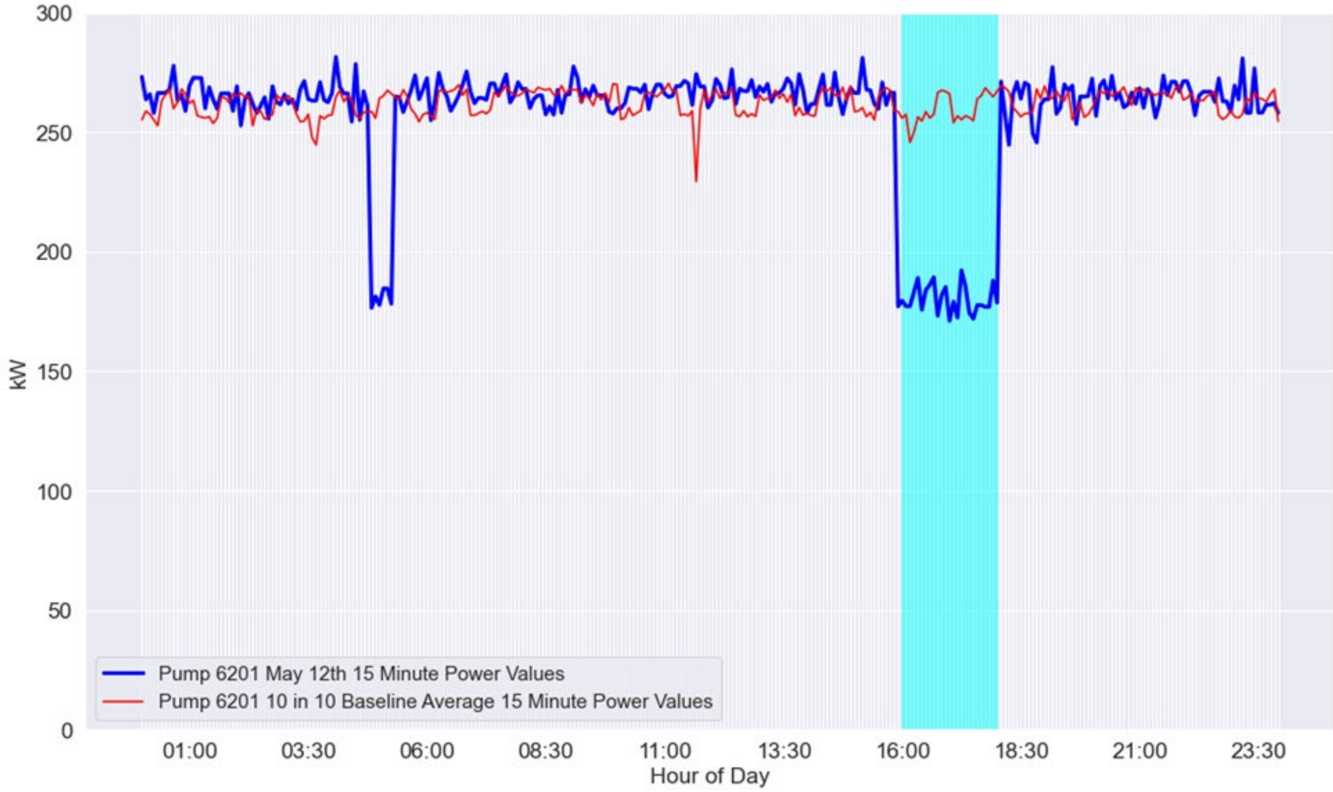
Results

The project team compared loads for DR days to a baseline constructed using the California Independent System Operator (California ISO) "10-in-10" rule, in which the baseline is the average of the 10-preceding qualifying (non-DR) days, adjusted for actual consumption on the day of the DR event. Each DR event day's load profile is compared with its 10-in-10 baseline profile in Appendix F. Figure 3-1 shows an example of the load reduction.

Tubeway Station hosts two variable-speed pumps. For the second DR event on May 18, 2021, pump 6202's (the second variable-speed pump) power was mistakenly reduced instead of 6201. For the May 18, 2021, DR event, pump 6202's power reduction is compared to pump 6201's baseline.

During the June 10, 2021, DR event, the operator mistakenly turned on the 6201 pump one hour ahead of the event's completion, thus the resulting reduction for this DR event is about 10 percent less than the others. The operator noted that it was a mistake and not operational constraints that caused him to raise the pump's power.

Figure 3-1: May 12, 2021, Pump 6201 Daily Load Example During a DR Event Day



Graph showing pump 6201 daily load on May 12, 2021. There is a 79.12-kW reduction during a DR event from 4:00 p.m. to 6:00 p.m., compared to the 10-in-10 baseline.

Source: EPRI

On June 8, 2021, the operations team alerted the project team that they would reduce the pump power one hour before the DR event to fit within the schedules of two operators changing shifts.

The field test results showed on average a 79-kW reduction in pump power across all eight DR events, compared to the baseline. This translates into a 30 percent average power reduction across the DR event periods. The results show that the Cal Water operation team operating on the zone D system can demonstrate flexibility when operating the 6201 pump during DR event periods.

The consistency of DR event opt-ins during the field tests is encouraging and suggests the potential for greater flexibility and feasibility of opting in within the broader Cal Water system. The operators noted that the tool provided overarching guidance for their decisions, but they did not use the tool prescriptively. The operators used intuition as to whether a given opt-in was feasible based on historical experience with the system. The tool's day-ahead forecast for tank volume provided a forecast within 25 percent error on days with DR events. Given the high variance in daily operation in Zone D, this is a suitable accuracy for a forecast based on historical data. There is certainly a niche for significant DR impact within Cal Water and similar water pumping entities if incentivized through market incentives and operationally guided through decision making tools like the flexible water pumping decision support tool.

Summary of Results

The primary innovation of the water pumping field test was the design, implementation, and field test of a decision support tool designed to engage water system management supervisors and operators in DR. The hypothesis of this work is that it is possible, through data analysis, to provide accessible and actionable information to system operators that enables them to decide whether to opt-in to a specific DR event. The tool provides guidance on the feasibility of power reduction during DR events without obstructing operational constraints.

Achieving Goals

Using this decision support tool, the project team was able to achieve the expected 20 percent demand reduction from Cal Water's Pump 6201. The project objectives were met, and the field test was able to demonstrate demand flexibility within a water pumping system using the decision support tool as a guide. At the conclusion of the project, 8 out of 9 DR events were successful, with a 30 percent reduction in power averaged across all DR events. It should be noted the one failed DR event was not due to operational constraints or demand limitations, but rather the operator selected the incorrect pump for power reduction during the DR event. The decision support tool functioned as expected and presented no significant challenges to the operators.

The field test's results show that Cal Water Zone D's operational flexibility could readily assist the grid during periods of high stress through load reduction if financially incentivized. The decision support tool proved to be efficient in providing overarching guidance for the Cal Water operators in deciding whether to opt into a DR event. Although the operators had intuition from experience on whether the system could sustain a DR event, the tool presents a medium for the operators to understand and discuss the effects of a DR event on the system given their defined operational constraints.

Prototype Demonstration

The decision support tool was demonstrated as intended. Appendix E details the designed decision support tool.

Proven, Validated Competitive Advantages, Scale, Commercial Readiness, and Value

The decision support tool operated successfully throughout the field test. The demonstration showed that water pumping entities have the ability to participate in DR when given the tools to quantify the effects on the system and its operational constraints. The decision support tool provides water pumping entities the guidance and confidence to participate in DR and ultimately provides value to the electricity grid through renewable integration and reliability. The tool also garners financial value to the water pumping entity if DR is incentivized through electricity market rates or DR pay-for-performance programs. Although the tool was successfully demonstrated and proven at Cal Water's Zone D, it is not ready for widespread commercial adoption. Integration with other water pumping entities' existing automation systems, as well as generalizing the tool for broader use, is necessary before commercial adoption.

Filling Knowledge and Data Gaps to Adopt More Aggressive Energy Standards

Water pumping entities' number one priority is meeting water demand within their operational constraints. Without underlying knowledge on how a DR event may affect the system, water entities may be hesitant to participate in DR events. The decision support tool addresses the knowledge and data gaps that may prevent water pumping entities from participating in DR. The tool takes data from the various pump and tank sensors within the system and provides a data-driven forecast of DR event on the system. With this knowledge, operators are able to make more informed decisions on whether the system can opt into a given DR event. With this tool providing operator guidance, grid reliability can be improved by engaging water pumping entities in DR. This can ultimately help achieve energy standards by lessening the need for additional power plants to meet electricity demand needs.

Identifying, Verifying, or Minimizing Unintentional Consequences

Currently Cal Water is able to pass energy and demand related costs onto the customer. Hence, their operational focus is not on energy and demand efficiency, but rather on meeting customer demand. In the future, Cal Water will be responsible for their energy and demand usage.

Major Lessons Learned

The field test results showed that DR is plausible within Cal Water's Zone D and that the decision support tool may be useful for engaging similar entities in DR without obstructing operational constraints. To extend the decision support tool to other pumping entities proper sensors, data acquisition, and system knowledge must be present. The tool requires reliable information on the system and its components to produce a forecast. Hence, in the early stages of integrating the tool, the proper personal must be involved in defining the system's structure and operational constraints. Operators who will use the tool should be involved throughout the process and should understand that the tool is only a guide; the operators have the ultimate control over how the system operates. Facilitators of the tool should provide operators opportunities for discussion and answer questions to help increase their comfort and familiarity with the tool. It is also important to make the operators aware of the overarching goal, and to inform them that their operational actions can assist the electricity grid and society as a whole.

Research Needed

Although the tool was successful demonstrated, more research is needed to advance its maturity towards commercial adaptation. More datapoints and operational experience on the system can improve forecasting methods, including adoption of machine learning-based approaches, which are very well-suited to this data-driven application. Expanding the tool to more sites and larger-scale demonstrations will advance generalization of the tool and the components necessary for widespread adoption. Future research on response speed, direction, and duration can provide more insight and value in terms of feasibility of DR within pumping systems. Integration with energy optimization software and existing systems will facilitate tool use and improve user interaction.

Economic Savings

Overview

Cost savings were not part of the scope of this field test, and indeed were not expected, since Cal Water is not currently enrolled in an electricity rate structure that financially incentivizes DR. Although cost savings are not expected in this field test, customer participation in DR events will not occur unless there is a financial incentive, so it is instructive to consider how financial benefits may result from future implementation of this technology at scale.

Since the reduction in energy during the DR event is simply shifting the load to another time, not reducing the load itself, there are no energy savings associated with reducing pump power during the DR event. As a result, there are no economic savings directly correlated to energy efficiency from this field test. However, this analysis considers three other avenues in which economic savings are possible, depending on the electricity rate schedule in question:

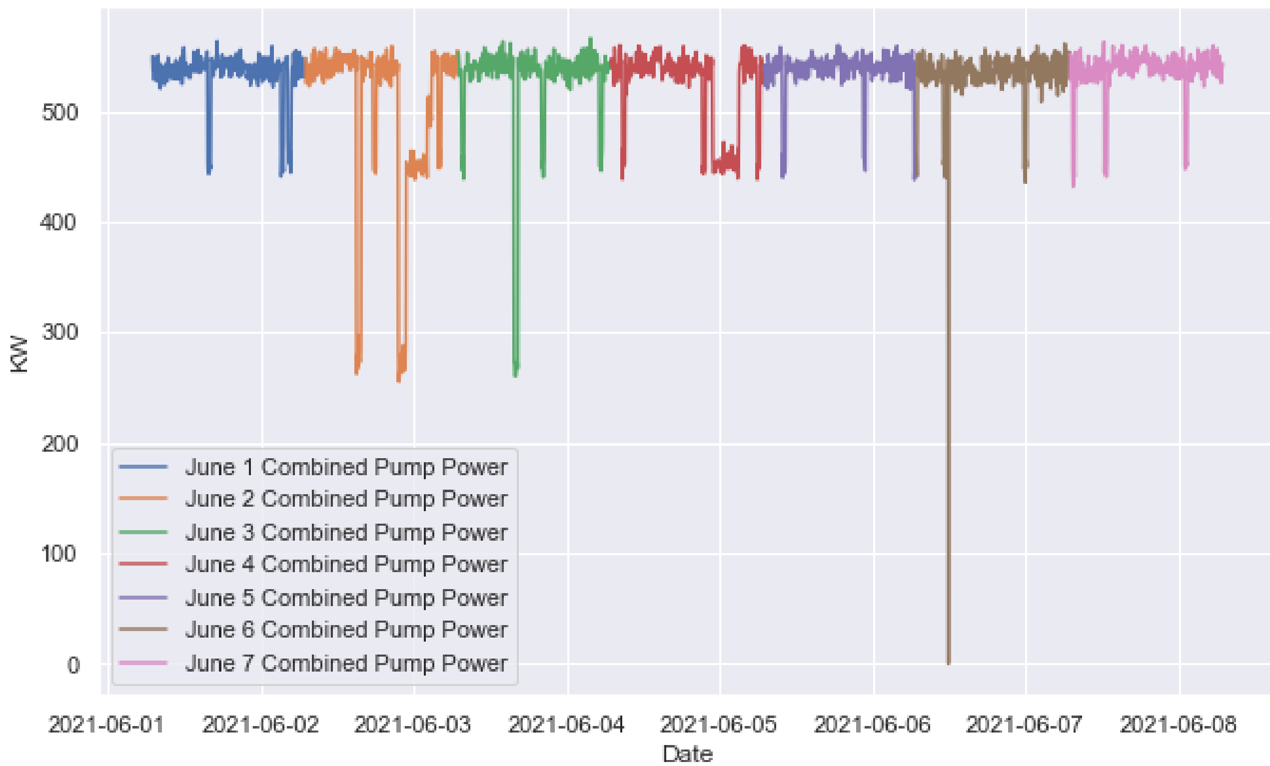
- Demand cost reduction.
- Load shifting to lower cost periods.
- DR pay-for-performance programs.

Demand Cost Reduction

The first scenario assumes an electricity rate schedule that charges customers specifically for demand. In this scenario, the reduction in power during DR events may lower the system's overall peak power consumption for the billing period. In this case, economic savings would occur via reduction in demand cost and would be based on the demand pricing and regulations for the given rate schedule. The results of the field test show that Cal Water's peak power consumption times are irregular and are not correlated to the time of DR events. Thus, this scenario produced no economic savings.

Figure 3-2 provides a graphical representation of Cal Water's Tubeway Station total pump power for the first week in June. In this typical week in June, the combined peak pump power consumption consistently changes, and the peaks are not associated with a particular time of day. The variance seen in the times in which peak power consumption occurs continues to be high throughout the field test's duration, and none of the peak demand times at Tubeway Station occurred during a DR event. This means the field test's DR events had no effect on reducing the system's peak electricity demands, which occurred outside of DR event times. As expected, electricity bills provided from Cal Water showed no significant reduction in cost associated with demand when compared to the previous year. Water pumping entities that routinely experience peak power consumption from 4:00 p.m. to 8:00 p.m. are more likely to achieve cost savings from this scenario. This is the timeframe when DR events usually occur, although they can be called any time depending on grid needs and the rate schedule or DR program in question.

Figure 3-2: Cal Water's Tubeway Station Total Pump Power for the First Week of June 2021



Graph showing the Cal Water's Tubeway Station total pump power for the first week of June 2021 in five-minute resolution

Source: EPRI

Load Shifting to Lower Cost Periods

The second scenario assumes that Cal Water uses a direct access provider for electricity and considers the economic impact using California ISO's locational marginal prices (LMP) for the regional pricing node closest to Cal Water: "TH_SP15_GEN-APND." In this scenario, the savings are derived from the DR event power reduction occurring when the cost of energy from the LMP is higher, while the load increase to make up for the DR event is shifted to a period when the cost of energy is lower. The field test DR events occurred when the cost of energy was highest from around 4:00 p.m. to 8:00 p.m. Under this scenario, some savings could be expected, assuming that the load is shifted to lower-cost periods. These savings are still hypothetical, however, because it was out of the scope of the field test to quantify when and where in the system the load that is reduced during the DR event is made up.

To estimate the cost savings in this scenario, the entire day of the DR event is considered to possibly capture when the make up in load occurs. The cost for the DR event day is derived from the hourly product of the event day's cost and pump 6201's average power for that hour, summed for each hour of the day. The 10-in-10 baseline cost is computed from the hourly product of the event day's cost and the pump 6201's 10-in-10 baseline power averaged for that hour, summed for each hour of the day. The DR event day impact is then calculated by subtracting the DR event day cost from the 10-in-10 baseline cost.

Each day's cost is highly dependent on the water pumped and total water demand needed for that particular day. Thus, the economic impact is not directly correlated to the DR responses, and the economic impact can significantly vary due to the daily variation in pump 6201 operation. To address this operational variation, the team performed a normalization on the total amount of water pumped on the DR event day to match that of the water pumped on the given 10-in-10 baseline day. Table 3-2 shows the results of this normalization. After considering all these factors, the team did not find any statistically meaningful cost savings that resulted from the intersection of DR events and LMP.

Table 3-2: Pump 6201 DR Cost Impact Results

DR Event Date	DR Event Time	DR Event Day Impact ($)	DR Event Day Cost Normalized by Total Gallons of Water Pump ($)	10-in-10 Baseline Day Cost ($)
May 12, 2021	4 to 6 PM	-20.47 (savings)	2304.70	2325.18
May 18, 2021*	4 to 6 PM	NA	NA	NA
May 25, 2021	4 to 6 PM	-21.23	2183.78	2205.02
May 27, 2021	4 to 7 PM	-3.56	1704.07	1707.63
June 2, 2021	4 to 7 PM	-38.48	2577.18	2615.67
June 4, 2021	4 to 8 PM	-126.59	2528.86	2655.45
June 8, 2021	5 to 7 PM	24.56	1515.43	1490.87
June 10, 2021**	5 to 8 PM	25.20	1357.38	1332.18
June 17, 2021	5 to 9 PM	-224.34	4068.38	4292.72

* Because pump 6202 power was accidentally reduced instead of pump 6201, this event is excluded from calculations.

** Pump power was accidentally increased one hour before DR event conclusion.

Source: EPRI

DR Pay for Performance Programs

The third scenario assumes that Cal Water is under a pay-for-performance electricity rate schedule that financially incentivizes DR through program participation credits. In this scenario, savings are achieved through some sort of bill credit or price reduction that the utility awards to the customer for shedding load during a DR event or peak pricing periods. The cost savings from the scenario depends on the rate schedule and DR program, as well as the power reduction achieved. The field test's power reduction results show that this specific water pumping entity has the capacity for flexibility in operation and could readily benefit the grid during periods of high stress if financially incentivized. Penalties should also be considered in the scenario if Cal Water is unable to meet its expected demand reduction during DR event or peak pricing periods.

Technology Readiness Level Advancement

In summary, the FEMS application was designed to support decision making of plant operations personnel for DR event participation. This system required significant conceptualization and design in early stages and was first tested in a simulated environment by EPRI, bringing its TRL from 3 (Prototype Developed) to 5 (Pilot Demonstrated) through the project. Various DR strategies were supported by the FEMS application, including power down strategies with adjustable-speed pumps and both power up and down strategies with refrigeration equipment. To advance to TRL 6, these strategies were demonstrated in real-world test environments. Full-scale demonstration in real world commercial office environments with multiple test sites would be the next step to advance to TRL 7. Demonstration of power up and power down applications as strategies available in integrated optimization and control systems could reduce technology deployment costs and help boost the TRL to 8-9.

CHAPTER 4: Project Results: Refrigeration Plant

Modeling Analysis and an Improved DR Experiment

In the first set of experiments (described in Appendix G and termed "calibration" tests), the project team evaluated the system response in terms of compressor electrical demand to two types of events: "power up" and "power down." In power-up events, the intent was to increase the average power demand over the duration of the event, compared to the baseline demand, by lowering the setpoint of the frozen room temperatures to -20°F (-29°C). At the end of the event, the setpoint was returned to its original value of 0°F (-18°C). In power-down events, the thermal mass in the frozen rooms, constituted primarily by the food, was pre-cooled for a duration equal to the duration of the power-down event, immediately prior to the beginning of the power-down event, by reducing the temperature setpoint to -20°F (-29°C). At the beginning of the power-down event, the temperature setpoint was returned to its default value of 0°F (-18°C), with the expectation that the sub-cooled thermal mass would keep the air temperature below the setpoint during the event, thereby reducing the compressor power demand. The inherent assumption is that there is symmetry in the charging and discharging of the thermal mass, so that the extra energy the compressors use to sub-cool the thermal mass during the pre-cool period is recovered in the subsequent power-down event.

This first set of calibration experiments conducted in the fall of 2020 showed, against expectations, that obtaining an increase in power consumption is far easier than obtaining a decrease in power consumption. Specifically, the increase in power demand for power-up events exceeded the expected amount, while the decrease in demand for power-down events was smaller than expected. To understand the reason for the asymmetry, the EPRI team developed a simplified thermal model that describes the main features of the dynamic interaction between the compressors-evaporators, the air and food in the frozen rooms, and the frozen room envelope, constituted by the floor, walls, and roof. The model revealed important features of the heat transfer processes between the evaporators, the freezer room surfaces, the floor heaters, and the food, as follows:

1. The heat transfer process (cooling of the air mass) occurs relatively rapidly, with a time constant on the order of one hour.
2. Once a temperature difference of several °F is established, effective heat transfer can be established between the air and the food.
3. Because of the high thermal mass of the food (each frozen room contains several thousand tons of food), the rate of change of temperature is slow, even when room evaporators operate at maximum capacity.
4. The system controller tracks the air temperature, not the food temperature, although the heat content is primarily in the food. Consequently, changes in food temperature always lag changes in air temperature.
5. The heat produced by the floor heaters, which eventually ends up in the freezer room space, is likely a significant contributor to the heat balance in the room.

6. Control parameters that are set in the PID control can affect the dynamics of the system, particularly the speed of the compressor, and the activity of the compressor following a temperature reset. Care should be taken in determining the setpoint, because the time integral of the tracking error can lead to unexpected consequences.

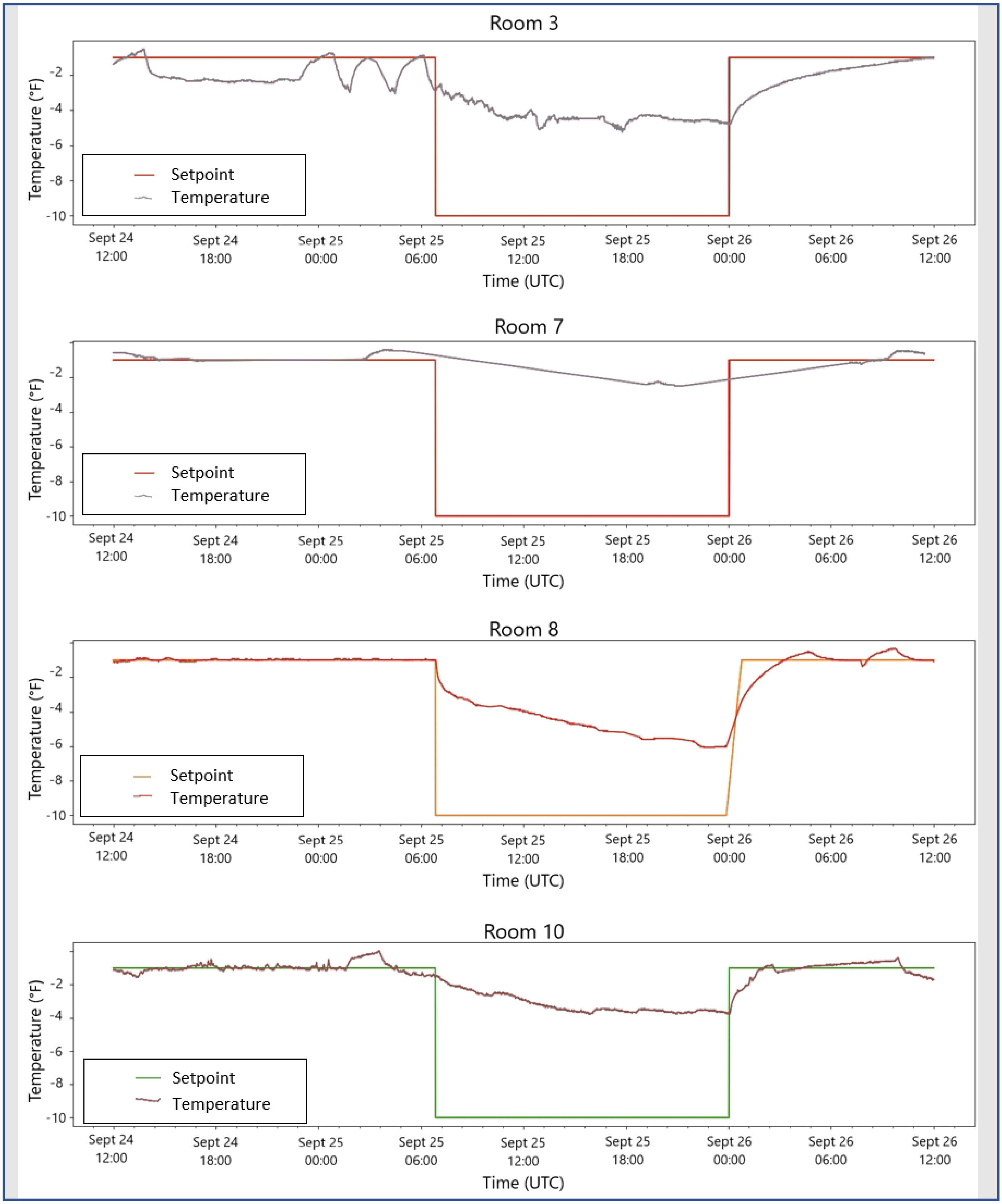
Appendix H contains the detailed modeling analysis. Based on these insights, the EPRI team, in consultation with CrossnoKaye and Lineage, designed an improved procedure and implemented it on an experiment conducted on the weekend of September 25-26, 2021.

The rationale behind the new experimental design was that excessively low setpoints appear to produce an excessively large integral component in the PID, that in turn re-activates the compressors soon after the power-down event is initiated. In addition, a sufficiently long period of time is necessary to lower the temperature of the food. Too short a time would only reduce the temperature of the air, which has a relatively low thermal mass compared to the food. A power-down DR event was conducted on the weekend of September 25-26, 2021. During the weekend, the transfer of food in and out of the frozen rooms is minimal, reducing experimental "noise." As an additional measure to reduce noise, the defrost process for the frozen rooms was de-activated during the DR event. Figure 4-1 shows the temperature setpoints for the improved experimental design for the four frozen rooms (#3, 7, 8, and 10) in the DR event.

To reduce the integral of the tracking error that is thought to be responsible for asymmetry in the power-down versus power-up behavior, the setpoint for the pre-cool period was set to -10 °F (-23°C), unlike with previous experiments, where it was set to -20°F (-29°C).

While the DR setpoint schedule was the same for all rooms, the response was not uniform, due to different room configurations, food storage situations, and prior defrosting events. The response of Room 8 was closest to the analytical model. In Room 8, prior to the pre-cooling event, the air temperature tracked the setpoint very closely for at least 18 hours. At the onset of pre-cooling, the expected exponential decline of air temperature, lasting less than one hour, was observed, followed by the quasi-linear decline in temperature associated with heat removal from the food. At the end of the pre-cool period, the air temperature climbed exponentially, driven by floor heating, heat transfer from the perimeter walls and roof, introduction of food pallets, forklifts, and defrost cycles. Figure 4-2 shows the sources of heat inside a frozen room. The temperature response for rooms 3 and 10 reflects the fact that defrost cycles occurred just before the DR event, so only the quasi-linear part of the cooling response is visible.

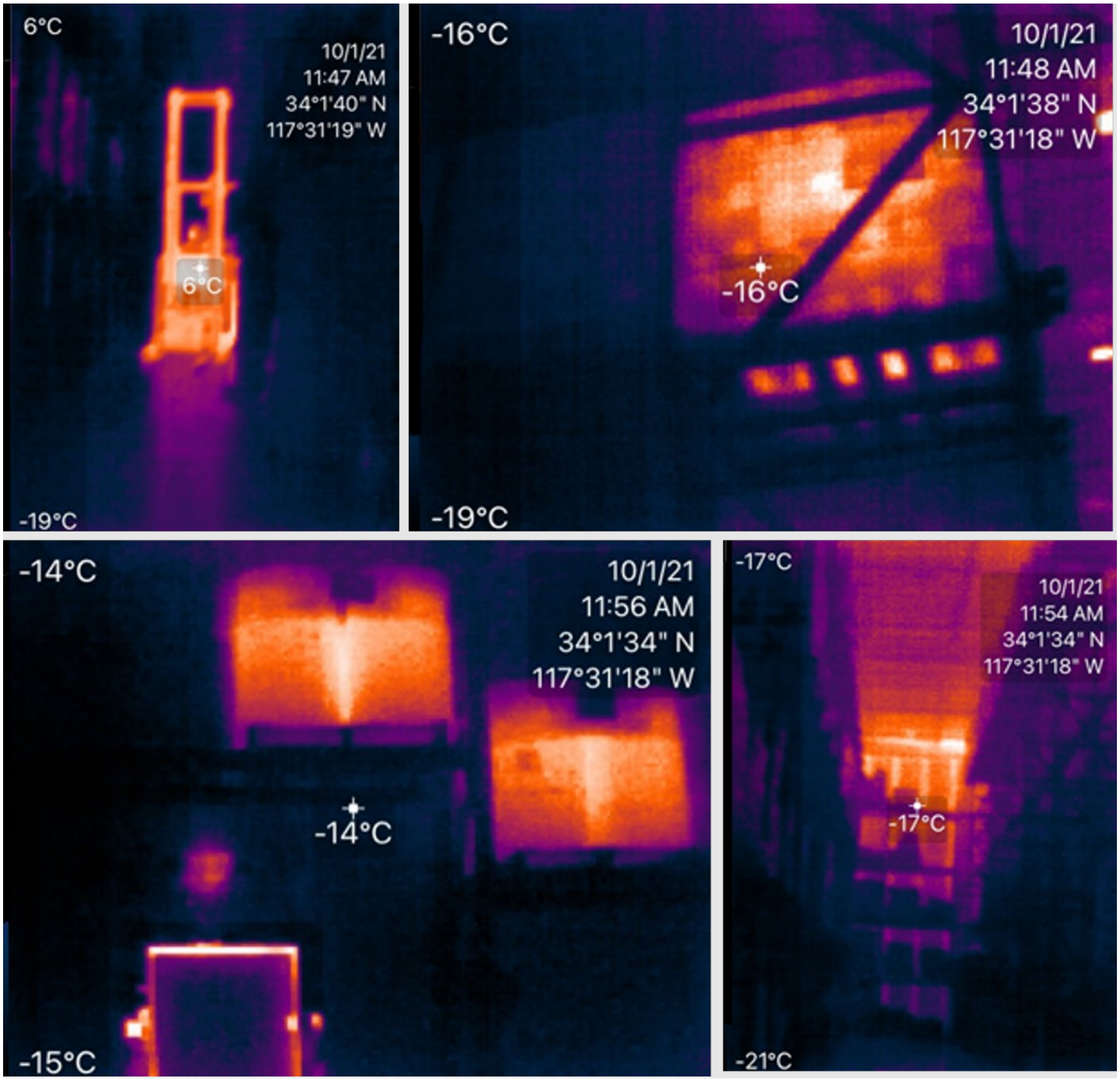
Figure 4-1: Temperature Setpoints and Air Temperatures for Frozen Rooms #3, 7, 8, and 10



Graphs showing the room setpoints and air temperatures in the DR event on September 25-26, 2021, in the improved experimental design

Source: CrossnoKaye

Figure 4-2: Thermal Images of Heat Sources Inside the Refrigerated Warehouse

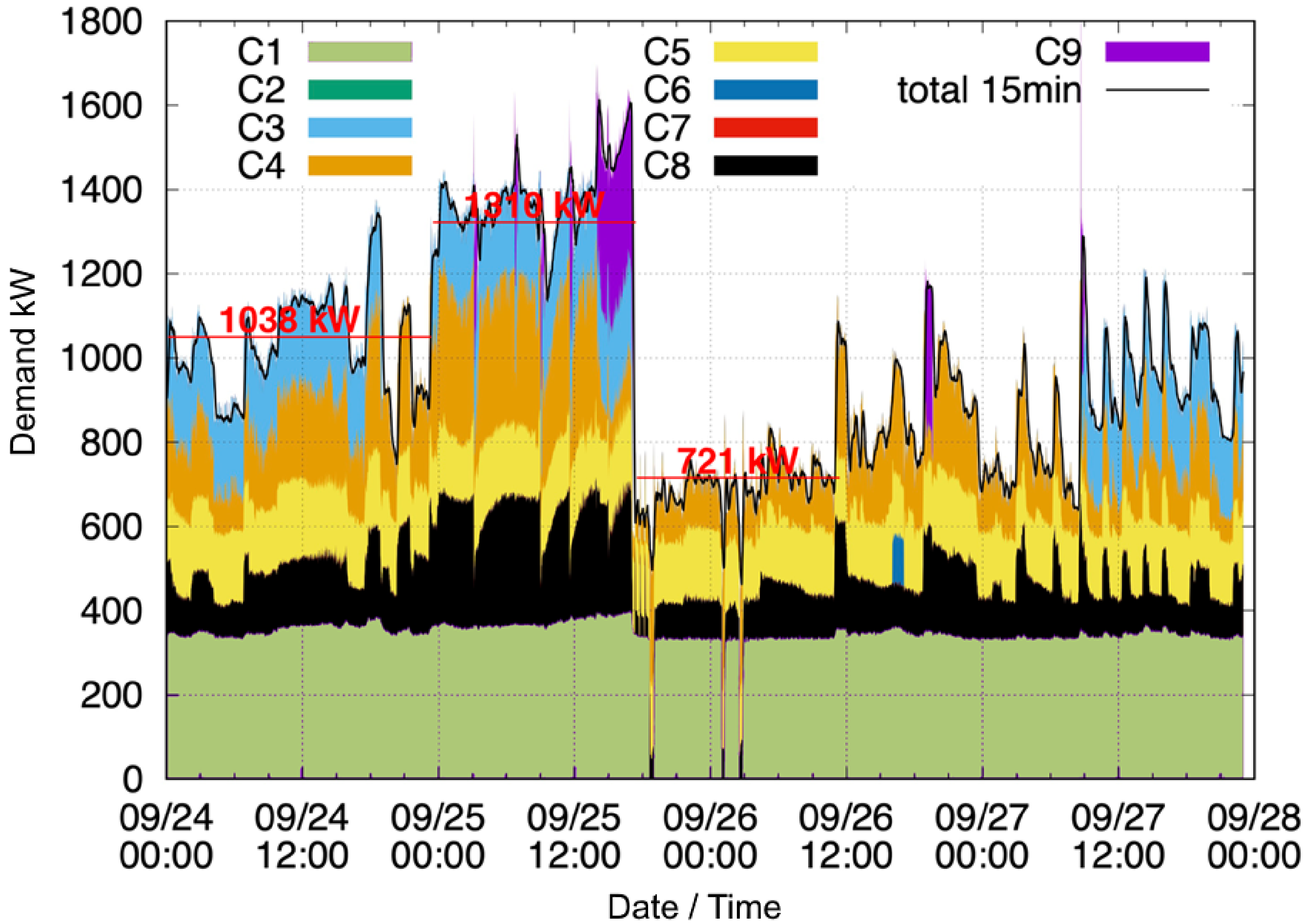


Sources of heat inside a frozen room (clockwise from top left): an electric forklift, food pallets, food pallets and drums, and perimeter walls and ceiling

Source: EPRI

Figure 4-3 shows the power response. Noting that the time is in PDT, the pre-cool period begins at 12:00 a.m. on Saturday, and lasts until 5:00 p.m. on the same day. The baseline average power draw from all the compressors before the pre-cooling period is 1038 kW. During pre-cooling, the average power draw is 1310 kW, or 26 percent higher than baseline. In the power-down period, after the pre-cooling, power draw drops to 721 kW, or a 30 percent reduction compared to baseline, and is sustained for a period of the same length as the pre-cooling period, from 5:00 p.m. Saturday, September 25, 2021, to Sunday, September 26, 2021. After the DR period, power draw slowly climbs back to baseline levels.

Figure 4-3: Power Demand for Improved Experimental Design Event



In the improved experimental design, power response of all chillers (C1 to C9) to the DR event consisting of a pre-cool period from 12:00 a.m. to 5:00 p.m. on September 25, 2021, followed by a power-down event until 12:00 p.m. on September 26, 2021 (compressor C7 is inactive)

Source: EPRI

Summary of Results

The refrigeration plant sub-project involved three phases:

- A setup phase established an end-to-end communication pathway to send DR signals and to receive feedback.
- A preliminary experimental phase enabled understanding and calibration of the response of the refrigerated warehouse temperature control system to different types of control input.
- A final phase demonstrated the performance of the final DR control design.

The dual project goals of demonstrating a "generic" infrastructure for the communication pathway, and demonstrating the feasibility of attaining substantial flexible DR, were met successfully.

Infrastructure for Communications Pathway

The project demonstrated the effectiveness of end-to-end, bidirectional, automated communication (using OpenADR2.0b). The project team built the end-to-end communication pathway through a combination of "off-the-shelf" components (for example the GridFabric VTN, the MelRok OpenADR Client) and some "custom" components (such as the integration of the MelRok OpenADR client with the CrossnoKaye schedule delivery system). The team also validated the applicability of the OpenADR 2.0b specification, where a return signal is sent back to the DR server validating a demand increase or demand reduction action taken by the end-use system.

Feasibility of Attaining Substantial Flexible DR

The project team demonstrated the system's ability to produce sustained "flexible" DR (30 percent of total compressor load) in both up and down directions for extended periods of time (greater than 12 hours). While making substantial headway to commercial readiness, it is the team's opinion that more demonstrations are necessary to substantiate the value proposition for flexible DR in the refrigerated warehouse sector. For a future demonstration project, additional components can include:

- Utility rate structures that reflect the true price of electricity at the time of use (true real time price).
- Real-time price signals from the energy service provider that can be easily understood by the system.
- Such DR signals that can be incorporated into a schedule optimization service by the customer.

Filling Knowledge and Data Gaps to Adopt More Aggressive Energy Standards

This sub-project demonstrated a technology pathway to achieve flexible, automated DR with industrial refrigeration. While a full economic analysis was beyond the scope of the project, information obtained from the project collaborators indicates that there is an economic case for implementing such systems at scale. Specifically, taking advantage of the embedded thermal storage capacity in refrigerated warehouses in response to price fluctuations is already providing cost savings to customers. Incorporating flexible DR can provide similar advantages, but it requires the development of pricing structures that compensate customers for DR participation.

Identifying, Verifying, or Minimizing Unintentional Consequences

Plant operation is optimized to take advantage of market fluctuations in the cost of energy, which may not reflect parameters such as emissions. Hence, current plant operation may not be optimal from an emissions perspective. As the cost of emissions and the value of increased penetration of intermittent renewables is increasingly reflected in the price of delivering power, plant operations and emissions reduction will increasingly align.

Major Lessons Learned

Research in the refrigeration sub-project highlighted the need to fully understand the dynamics of the thermal processes in the plant to enable accurate DR delivery. Furthermore, the design of the control actions must be tailored to the equipment (such as the type of refrigeration plant), the facility (for example the enclosure), and the local electricity rate structure (including compensation for DR participation). The sub-project also identified other opportunities for DR in refrigeration plants, which are of similar magnitude to the compressors, namely the floor heating system, and the electric forklift charging process.

Research Needed

Although the end-to-end DR process was successfully demonstrated, the application of DR was not completely optimized. For this to occur, two additional elements must be present:

- A DR compensation structure (even if artificial and confined to the research itself, as long as it is realistic).
- An integrated optimization server that can incorporate DR signals into the plant schedule optimization service.

The latter could be, for example, in the form of the newly released CrossnoKaye plant schedule optimization system, known as Atlas.

Appendix G describes the refrigeration site configuration, experimental setup, data validation, field test experiments conducted, and results of the "calibration" testing.

Floor Heater DR

Another potential source of demand reduction in refrigeration plants is the floor heaters (heat tapes). These heaters prevent the ground and foundation of the building from freezing and cracking. At this site, all of the floor heaters were electric resistance. (Note: Water/glycol floor heaters, using heat recovered from condenser exhaust, are used in some newer facilities.) While rooms 2-10 all have floor heaters installed, only rooms 4, 5, and 7 have automated controls with temperature and operational data monitoring. Therefore, these rooms were chosen for experimentation and analysis.

Following is the experiment methodology:

- A two-hour DR down event occurred on Wednesday August 4, 2021, from 5:00 p.m. to 7:00 p.m.
- The floor heater was controlled remotely by scheduling the setpoint of the floor temperature probes.
- Normally the setpoint is at 34°F (2°C), but during the DR event, the floor setpoint was set to 0°F (-18°C). Because of the thermal inertia of the floor, reducing the setpoint causes the floor heater controller to turn off the heater, as the temperature of the floor is allowed to drift downward.

The floor heaters were controlled by zone, and hourly operating data was used to determine if the floor heaters were on or off.

To account for the variability of operations, seven days of data before the event was collected, and an average daily load shape was developed as the baseline for the experiment. The baseline for a given hour is the power use at that hour averaged over seven days. Each floor heater zone exhibited different operating behavior, so individual baselines were developed for each zone. Based on the indicator and current transducer (CT) meter data, the power of each zone could be calculated. Figure 4-4 illustrates baseline development for all rooms. See Appendix I for data from all zones.

The operation for each zone during the event was then compared to the baseline average. Figure 4-5 shows sample results of this comparison. The difference between the baseline and the DR event during the 5:00 p.m. to 7:00 p.m. timeframe was then calculated, and the amount of demand savings for each zone was calculated. The total amount of demand reduction was 100 percent for the floor heaters, as all heaters turned off during the desired timeframe. This amounted to an average savings of 111.6 kW from 500 p.m. to 7:00 p.m. for the three rooms. See Appendix I for the breakdown of results for each room.

Figure 4-4: Rooms 4, 5, and 7 Floor Heater Operation Baseline

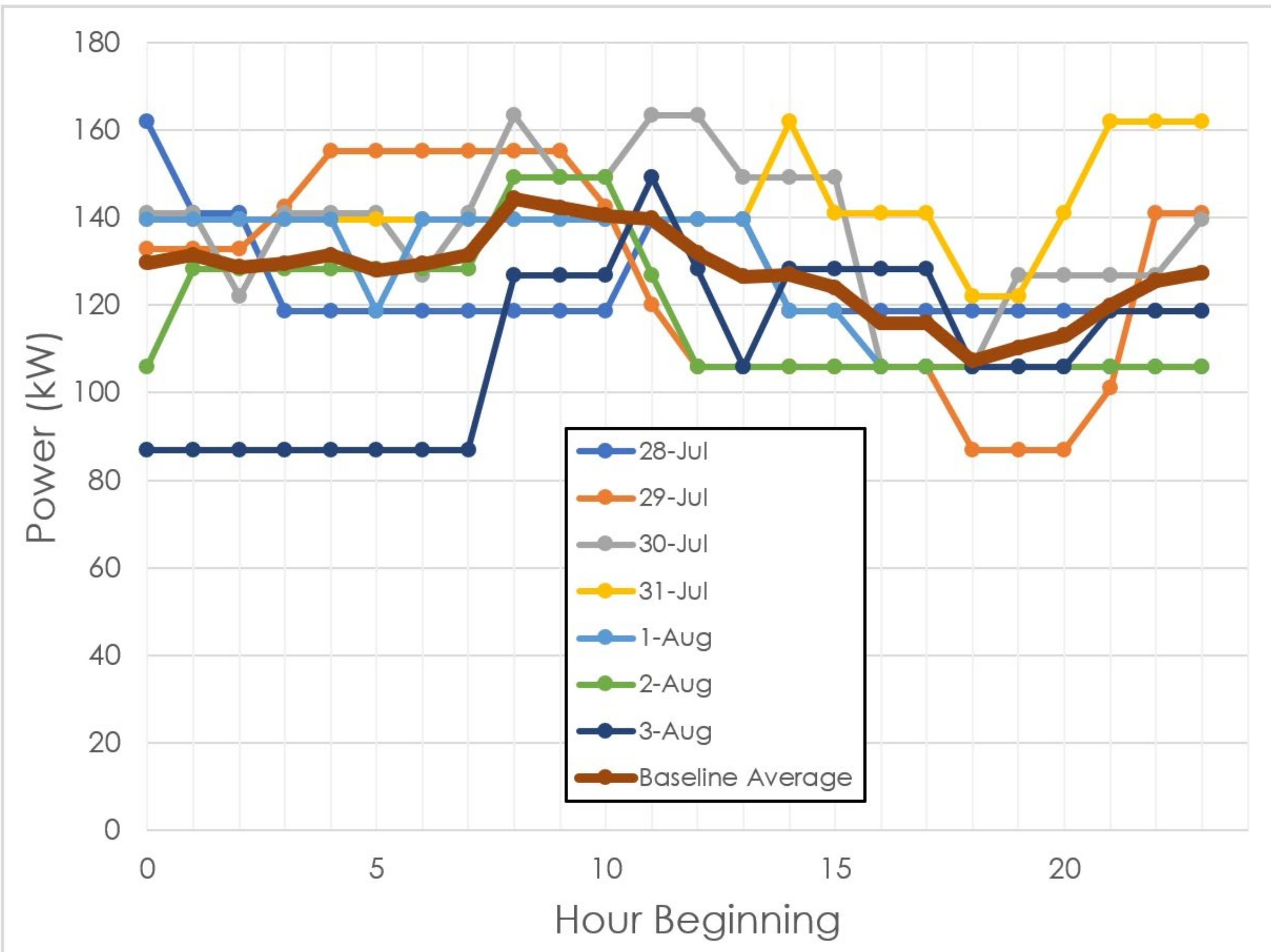


Diagram showing the floor heater baseline developed using seven days of historical data.

Source: EPRI

Figure 4-5: Rooms 4, 5, and 7 Floor Heater DR Event and Baseline

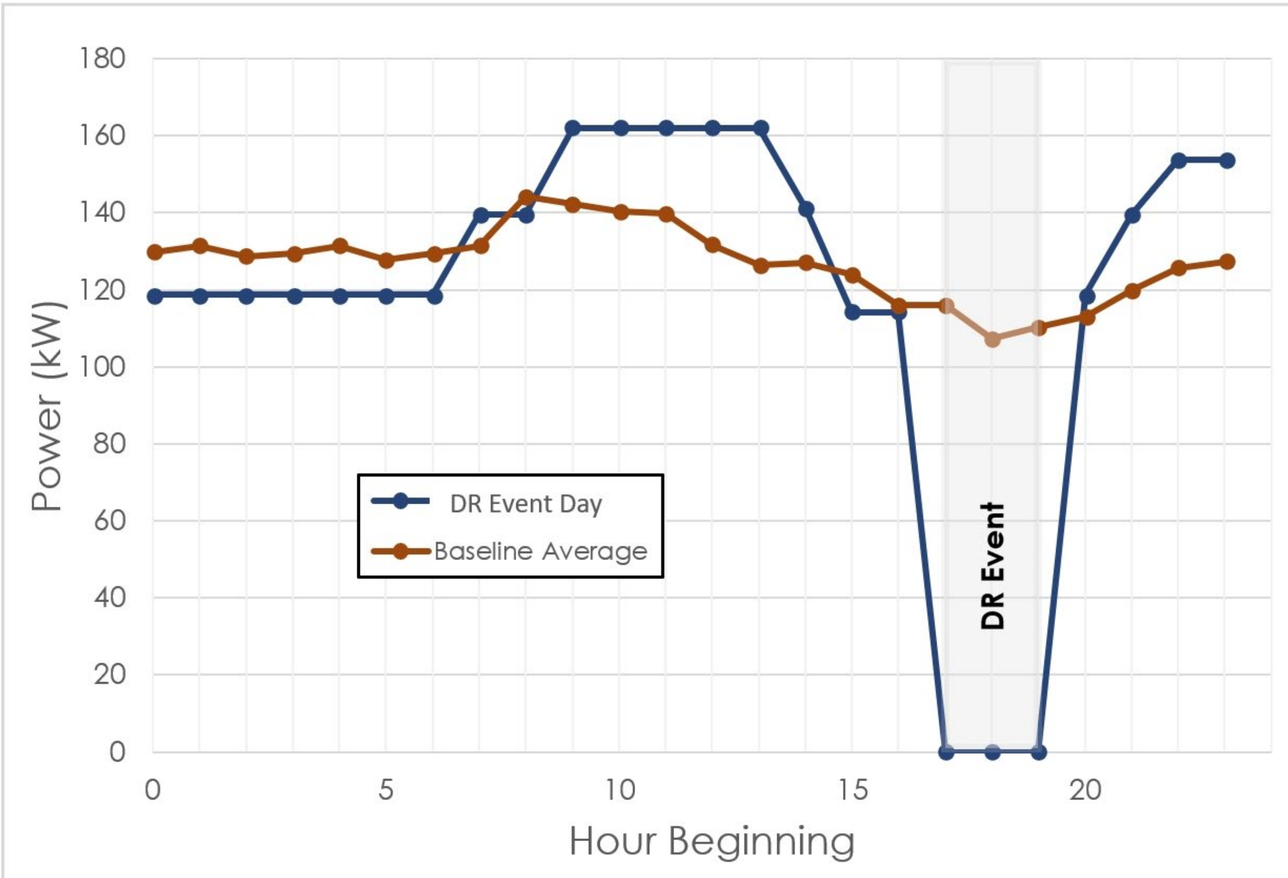


Diagram showing the DR event against the baseline average

Source: EPRI

As a secondary measurement and verification process, the total site power data from the SCE meter was collected, and the same procedure was used to calculate any savings. An averaged load shape baseline was developed using seven days of data before the event and was compared to the event power data. Since various other processes operate simultaneously within the refrigeration plant, the total site power measurements are not a precise measurement of the impacts of the floor heater DR event, but can indicate whether the impacts are noticeable. Figure 4-6 and Appendix I provide more details of this analysis. Using the total site power data, the calculated average power reduction from 5:00 p.m. to 7:00 p.m. was 163.5 kW. This is comparable to the 111.6 kW result calculated using floor heater data, considering the variance of daily data. The standard deviation of the difference between baseline data (July 28 to August 3, 2021) and the average baseline is 11 percent. The estimated 111.6 kW estimated power difference was only equal to 5 percent of the average entire site power (within one standard deviation of standard operating conditions), so the exact DR cannot be precisely verified with this data source.

Figure 4-6: Entire Site Power During the DR Event and Baseline

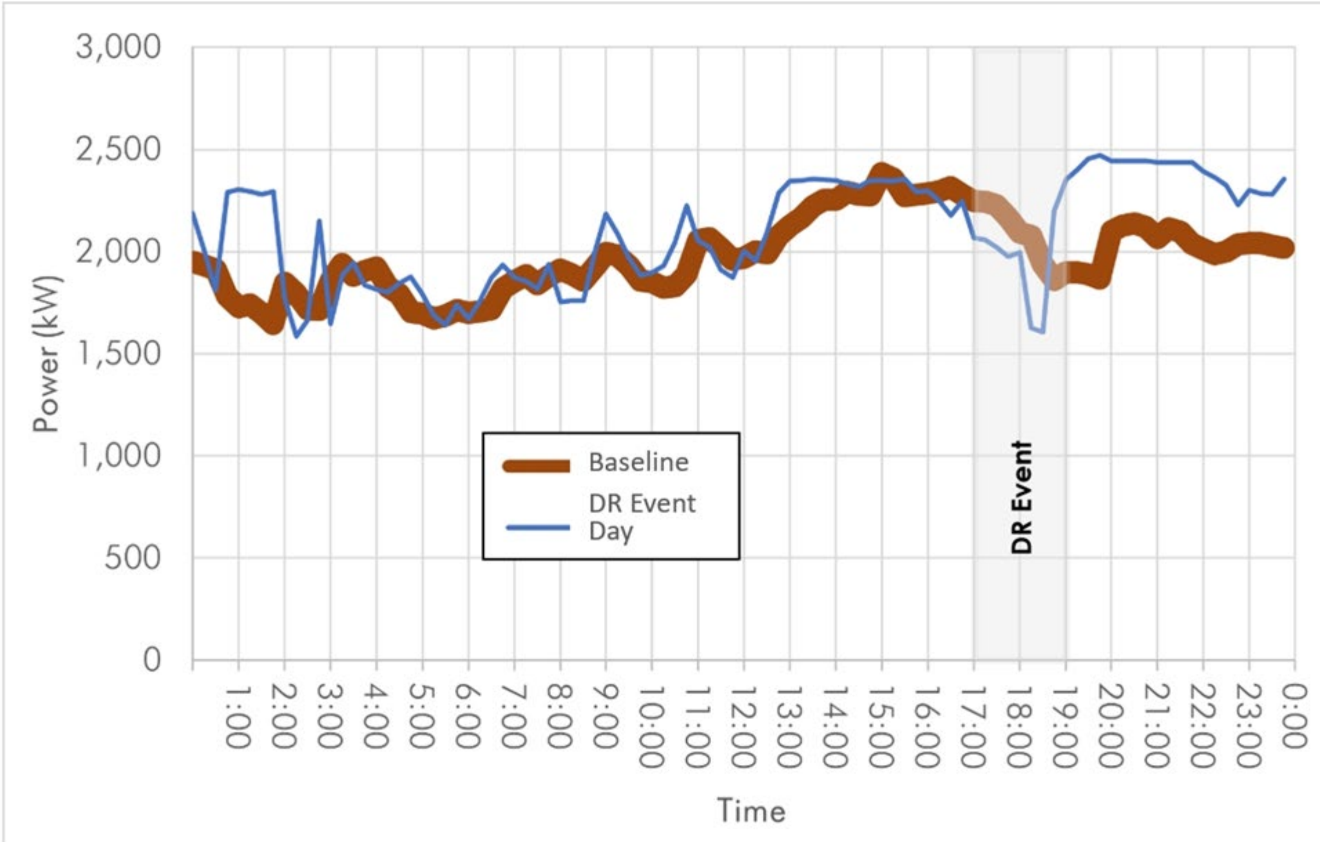


Diagram showing the entire site power during the floor heater DR event versus the baseline.

Source: EPRI

During the two-hour DR event, none of the temperature values decreased measurably in any of the zones. This shows that the concrete foundation provided sufficient heat capacity to maintain its temperature during the two-hour DR event.

CHAPTER 5: Technology and Knowledge Transfer, and Market Adoption

Water Pumping Technology and Knowledge Transfer

Market Adoption and Intended Use

Information from this research helps the electric power industry determine the potential for demand savings and load shifting in the water sector. Findings from the research also identifies functional and feature enhancements to the decision support tool that this sector needs to derive demand savings from DR participation. Water agencies may adopt tool upgrades necessary for flexiblity improvements. Moreover, Cal Water can expand use of the deployed FEMS to implement DR at one of its pumping stations.

Other types of commercial entities that may adopt an adaptation of FEMS include the wastewater sector, which can also benefit from FEMS and the influent and effluent pumping adjustment strategies outlined in the taxonomy section in Appendix A. Data scientists and researchers can leverage the pump load data captured in this project. Additionally, utilities cognizant of the research findings are using the information to inform future retail program developments that support system flexbility.

Target Markets

These market segments may benefit from FEMS adoption, because they share common characteristics that present opportunities for flexiblity and demand savings.

- In the near-term (2-3 years), the target markets for this technology are other extraction water pumping stations in the potable water sector.
- In the mid-term (4-6 years), the target markets also include water conveyance pumping stations, which typically have booster pumps for conveying water over longer distances.
- In the long-term (7-10 years), the target markets include the wastewater treatment sector.

Water and Wastewater Sectors in California

The target markets for this technology can be sized by referencing several studies. A LBNL-62041 [3] study estimates 467.6 MW of on-peak demand for the water sector and 205.3 MW for the wastewater sector served by the three California IOUs in 2004. A CEC study reports these three IOUs served 75 percent of total load in California in 2017 [4]. Moreover, a joint report by EPRI and the Water Research Foundation (WRF) estimates that electricity for water in the United States grew 39 percent between 1996 and 2013 [5] and will continue to grow. This corresponds to growth of about 2 percent/year. For wastewater, the annual growth was somewhat higher, at about 3 percent/year. Applying the 2 percent/year growth to the 2004 figures, the highest on-peak demand for the water sector can be estimated at 908 MW in 2023 across the state of California, whereas the highest on-peak demand for the wastewater sector can be estimated at 480 MW in 2023 for California.

Water Sector Addressable Market

Based on progressive levels of complexity, DR capability is expected to be expanded first in the water sector with water extraction pumping loads and then extended in the mid-term to include conveyance pumping and wastewater pumping systems. According to a 2017 SCE brief on energy management solutions for water and wastewater[5], water extraction pumping represents 11 percent of total load. The same source cites an additional 67 percent for distribution pumping. This means that water pumping is the primary electrical load in the water sector. The target market can be estimated by assuming DR participation of pumping loads in the near-, mid-, and long-term grows to 10 percent in the short-term (by year 2023), to 30 percent in the mid-term (by 2028), and to 50 percent in the long-term (by 2023) for extraction pumps. This reflects a reasonable assumption of less than 5 percent growth in DR enrollment per year over the next decade of engaging the water sector. Moreover, based on field test findings in the current project, a 30 percent reduction is achievable on average per DR event. Using these assumptions, the market potential in the California water sector for flexible water pumping is estimated at 27 MW by 2023, 90 MW by 2028, and 166 MW by 2023 for peak demand reduction. Moreover, the shiftable energy potential from water extraction and conveyance pumping is estimated at 197 GWh/year by 2023, 653 GWh/year by 2028, and 1202 GWh/year by 2023 in California.

Waterwater Sector Addressable Market

The market potential for wastewater pumping is assumed to occur over the mid- to long-term. The previously referenced EPRI/WRF report indicates that 12 percent of energy is used for wastewater pumping in the wastewater sector [5] (for example influent, effluent, and lift station pumping). Most of the energy use in this sector is for aeration (52 percent) and biosolids processing (30 percent). The breakdown of sewage through aeration and biosolids processing occurs continually over long periods of time. Hence, these high energy use percentages may not reflect peak power consumption. Rather, the percentage power consumption from wastewater pumping is assumed to exceed 12 percent. More specifically, for the purposes of market size estimation, wastewater pump participation in DR in the mid- and long-term is anticipated to be 10 percent and 20 percent, respectively, of the total highest on-peak demand of the California wastewater sector. This reflects a conservative assumption of 2 percent growth in DR enrollment per year over the next decade. Moreover, a 30 percent reduction is achievable on average per DR event, based on prior reported findings in an EPRI report [5] for a wastewater treatment plant that shed 30 percent of total facility load by controlling effluent pumping in a DR demonstration. Under these assumptions, the market potential in the California wastewater sector for peak demand reduction is estimated at 17 MW by 2028 and 39 MW by 2033. Moreover, the shiftable energy potential from wastewater pumping is estimated at 95 GWh/year by 2028 and 221 GWh/year by 2033 in California.

Overall Addressable Market

Overall, the total shiftable energy from the California water and wastewater sectors combined is estimated at 197 GWh/year in the short-term, 749 GWh/year in the mid-term, and 1423 GWh/year in the long-term. In terms of peak demand reduction, the estimated total from the

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[5] Which was itself based on data from the EPA's Smart Sectors Program (https://www.epa.gov/smartsectors)

two sectors is 27 MW in the short-term, 107 MW in the mid-term, and 205 MW in the long-term. Realization of the potential for peak demand savings and load shifting in each of the target markets will vary based on:

- Incentives driving economic business decisions.
- The ability of the water and wastewater sectors to maintain service to customers at adequate water and wastewater quality standards.

Technology Transfer Pathways

To spur market adoption, water system operators and DR aggregators need to be educated about the potential benefits of using water and wastewater pumping loads to benefit grid operations. Steps have been taken to facilitate technology transfer towards commercialization of the decision support tool developed for the field test. This is being accomplished by working directly with entities and project team vendors that can transition from project development into commercial production and use. Following are three pathways for commercialization:

- **Water agency.** Water utilities can implement the FEMS system, without involving an intermediary such as a DR aggregator. That is, a water agency can choose to develop and run FEMS in-house, outsource its development to a third party, or use FEMS software on a service provider's cloud or both. Regardless of the technology transfer path, however, developing awareness and interest among water agencies is an important first step along this technology transfer pathway.

  To realize this pathway to commercialization, customer pull or demand for FEMS technology is needed. To aid this process, the project team developed a video demonstrating operation of the FEMS proof-of-concept system implementation and posted the video online (https://youtu.be/ZYHeNY1iqXg). The video illustrates how water systems pumping can support DR without adversely impacting the water system's operating schedule or service to customers.
- **DR aggregator.** In addition to creating interest among water agencies in FEMS capabiltiies and adopting the technoiogies directly, third-party vendors (for example DR aggregators) can offer implementation and hosting for tools and algorithms developed in this project. Leveraging commonalities among water distribution operations, DR aggregators are well-positioned to construct and implement value-added analytic tools and systems to economically engage water agencies in DR, spreading the costs across multiple participants. Moreover, DR aggregators can host value-added services, such as forecasting tools, to help DR participants anticipate future DR events. Appendix J describes a Track and Trending tool that the project team conceptualized to leverage data streams readily available from market operators and public sources.
- **System integrator.** The proof-of-concept software that was developed for this project uses algorithms embodied in Python scripts that extract data from a historian database and analyze the feasibility of alternative pumping strategies for shifting pumping loads. Cal Water and many other water agencies use the OSIsoft Plant Information (PI) historian platform. Technology transfer can be facilitied by rebuilding the algorithms atop the PI platform, enabling end users to readily deploy FEMS software on their PI infrastructure or on a PI cloud service offered by OSIsoft or one of its system integrators.

To explore this pathway, EPRI shared a FEMS demonstration with a system integrator (KBC). This company specializes in plant instrumentation and PI system implementation using a real-time process data to build applications atop PI that solve technical problems. Through a series of exploratory conference calls with different groups within KBC, EPRI interviewed groups spanning its instrumentation, PI systems integration, and consultancy businesses, to discern the viability of this pathway. The goal is to leverage system integrator expertise in building applications native to the PI system, either locally-hosted or in the cloud. Although the vendor's expertise is well-suited to reimplementing the field test software, practicality depends on customer pull for a marketable solution native to the PI historian platform that most water agencies use.

Market Barriers

Technology Investment Costs

The cost of investments in technologies to increase opportunities for DR is a challenge for water system operators. Despite the existence of highly effective technologies (such as VFDs), their use in the United States, where energy is relatively low cost, is relatively low. The reason may be that many water systems are municipally-owned, and budget constraints can be significant. Financing models and incentive programs may not support the necessary up-front investment costs, and policy and regulatory mandates may not be sufficient to motivate such investments.

This situation may require that policymakers implement rebates and credits for technology retrofits. Advocacy of standards use, as well as other promotion and education, may also be needed to advance implementation of these technologies.

Education

Both water agencies and aggregators may benefit from an improved understanding of the financial value of providing DR in real-time and day-ahead markets. LBNL has found that knowing how much money could be available in real-time markets and how often resources would be dispatched can drive market adoption [6].

ISO Market Integration of Resources

The "shift" service type resource is the largest opportunity LBNL identified for DR to provide system-level value for the future grid [6]. With 20 percent of load shiftable, up to about $700 million/year in benefits are possible. LBNL estimated that up to about 10 percent of daily energy shifted in 2025 would be economically cost-effective DR. Resources such as water and wastewater pumping that can shift load into high-curtailment hours can offer significant capital investment and operational cost savings by reducing renewable overgeneration and overbuilding conducted to meet clean energy goals.

Baseline issues are challenging for existing "peak shed DR," which is only dispatched a few times per year. It is not clear how "shift"-type resources would fit into flexible capacity markets, and whether restructuring of compliance obligations are needed to qualify aggregations of shiftable loads. As a consequence, no market mechanism currently exists for compensating services like shift DR.

One reason for this is that establishing a baseline for frequently-dispatched resources like shift is quite challenging. Also, organizing and coordinating such resources for discrete dispatching can be difficult. This requires ensuring that that California ISO's market software can reflect the capabilities and operating constraints of the resources involved. Furthermore, mechanisms to compensate these resources for avoided flexible generation procurement (which may not be reflected in energy market prices) need to be identified.

Future Work for Technology Transfer

The project team recommends that project findings be shared through additional channels to further facilitate technology transfer. This includes conference venues, such as the IEEE Power and Energy Society (PES) General Meeting, for which the project team has submitted a paper and a proposed panel session on the topic for the summer 2022 conference in Denver, Colorado.

The trade and technical association of the water utilities in North America is the 140-year-old American Water Works Association (AWWA). The 4,300 utility members of AWWA are in organizations that move about 80 percent of the drinking water and 50 percent of the wastewater in the country. AWWA may be an efficient path for communicating the value of this project's work to most of the water utilities in the country (as well as to their software suppliers). Specific channels for such communication include AWWA's periodicals, *Journal AWWA* and *Opflow,* as well as its books, training manuals, standards, reports, and videos. The association hosts an annual conference, local section conferences, and specialty topic conferences. The proceedings of the annual and specialty conferences are published.

Refrigeration Technology and Knowledge Transfer

Market Characterization

Total Addressable Market

Food processing, storage, and transportation is a relatively large industry in California due to:

- The arrival and shipment of food (from and to overseas) in California ports.
- Transport of much of this food across the region and the country passes through the Los Angeles, Long Beach, and Bay Area ports.
- Large local demand for food due to California's large and relatively dense population.
- Large agricultural industry within California.

While some food that arrives in California ports bypasses California refrigerated warehouse storage (such as it is loaded directly onto trucks and rail for transport), a large amount of food is stored in California for later distribution within the state and the country for later consumption. The food stored in California warehouses for any length of time is the focus of this study and market opportunity.

According to the 2019 USDA report, gross refrigerated storage capacity in the United States totaled 3.65 billion cubic feet (103 million cubic meters) in 2019 [7]. A 2020 U.S. Department of Agriculture study identified 389 million cubic feet (11 million cubic meters) of gross refrigerated warehouse space in the state of California alone. Assuming an average of 60 tons of refrigeration capacity per million cubic feet (2100 tons per million cubic meter) [8] and an average of 1.3-2 kW of electric power per ton of refrigeration capacity, this translates to approximately 50 MW of total refrigeration electric demand for the refrigerated warehouse inventory in California[6].

Refrigerated warehouses are typically defined as facilities with more than 3,000 square feet (279 square meters) of refrigerated or frozen space, as opposed to smaller walk-in freezers. According to a 2015 LBNL study, "state wide demand response potential for the refrigerated warehouse sector in California is estimated to be over 22.1 Megawatts" [9].

More Detailed Analysis of California Refrigerated Sector DR Potential

The project team conducted a more detailed analysis of the estimated DR potential for California refrigerated warehouses. The United States Department of Agriculture (USDA) obtains data from surveys biannually concerning the size of refrigeration facilities in the United States[7]. The report contains data on the size distribution of refrigerated facilities. This is important because the energy efficiency of a facility is a function of its size, with larger facilities being generally more efficient than smaller ones. A 2008 CEC report [10] suggests the following average function of size:

$$SEC = 38.978 \times V^{-0.2275}$$

where SEC is the specific energy consumption in kWh/y/ft^3 and V is the volume of a facility in ft^3. Using these data, it is possible to estimate the total sector energy consumption for the United States, and proportionally for California. Table 5-1 shows the calculations and results of this analysis.

[6] 389 million cubic feet * 60 tons of refrigeration/million cubic foot * 2 kW electricity/ton refrigeration = 46,680 kW

[7] The latest data is available from the 2019 USDA report "Capacity of Refrigerated Warehouses 2019 Summary," (https://downloads.usda.library.cornell.edu/usda-esmis/files/x059c7329/zg64v297x/m326mj432/rfwh0120.pdf) published in January 2020.

Table 5-1: Total Estimated Refrigeration Sector Energy Consumption for the United States and California

U.S. Statistics (USDA 2019)					California*
Size Class (ft^3)	Number of Facilities	SEC ($kWh/ft^3/year$) [10]	Total Volume (000 ft^3)	Energy (MWh/year)	Energy (MWh/year)
250,000	145	2.31	36,250	83,579	8,907
750,000	95	1.80	71,250	127,946	13,636
1,750,000	195	1.48	341,250	505,360	53,859
3,750,000	220	1.25	825,000	1,027,262	109,481
9,000,000	260	1.02	2,340,000	2,387,510	254,450
All Class Total			3,613,750	4,131,658	440,333
Average Demand (MW)**				472	50
Peak Demand (MW)***				944	100
* Assuming 10.6% ratio across size classes ** Assuming 8760 hours per year *** Assuming that peak demand is two times average demand					

Source: EPRI

According to a 2020 report [11], Covid resulted in an 85 percent increase in demand for refrigerated facilities. Further, it is estimated that this added demand will result in speculative, rapid growth in such facilities. As a consequence, the assumption can be made that by 2025, the peak demand for California refrigerated facilities will increase by 85 percent from 100 MW to about 185 MW. With a historical growth rate of approximately 4 percent, in 2030 the expectation is for a peak demand from California refrigeration of 225 MW. Assuming that the potential for DR from refrigeration compressors is approximately 50 percent of peak load, this corresponds to a DR potential of 112 MW in California refrigeration warehouses by 2030. As was the case for the Lineage site at Mira Loma, refrigeration is not the only electric load that can be leveraged for DR. The load from floor heaters and electric forklifts adds a potential of the same magnitude, and it is not unreasonable to assume a total DR potential for California refrigeration warehouses of 200 MW by 2030.

Different loads can be leveraged for different types of DR. For example, floor heaters can respond immediately for a relatively short duration, while refrigeration loads associated with frozen rooms can last longer but require careful scheduling.

Similar technology could be applied to the approximately 4,700 supermarkets and grocery stores in California, most of which are associated with cooled and frozen rooms, further increasing the potential for the refrigeration sector.

Path to Commercialization

The technology needed for DR implementation in refrigerated warehouses is generally off-the-shelf and commercially-available from various vendors, and hence, technology is not a primary barrier to implementation. The EPRI project team is well-positioned to employ OpenADR 2.0b by leveraging EPRI's code (EPRI OpenADR Virtual Top Node) that has been openly shared and put in the public domain.

However, several control system considerations remain. There are various avenues for DR. One way is to simply reduce power and allow the optimization system to re-optimize based on current state. This may result in optimization that is below optimal, as there is no forecasting involved. A better way is to incorporate the DR action into the optimization directly, either by communicating a cost of energy that accounts for the requested DR action, or by imposing additional constraints on the optimization problem.

The path to commercialization requires addressing the current lack of marketplace awareness or definitive information on the DR value proposition for refrigerated warehouses. For example, how is the DR event requested (such as by participating in a capacity market or some other means)? DR in refrigerated warehouses must make economic sense or it will not be implemented. This project has demonstrated its viability; the next step would be a larger-scale demonstration at several refrigerated warehouses in California. During such a future demonstration project, the viability of fork-lift trucks to be DR-ready can be addressed.

Market Barriers

The primary barrier to entry is the extent to which operators of refrigerated warehouses can "keep the warehouse doors closed" while trucks are waiting to be loaded. The considerations vary depending on the business structure of the warehouse:

- Contracted third-party warehouse operators (for example Lineage Logistics) may be able to negotiate with the entities that receive their refrigerated product to accept delivery on a flexible schedule in some cases to reduce operator costs due to DR participation. The operator can consider sharing these cost benefits with the entities that receive their product as an incentive to enable this flexibility.
- Operators that manage grocery stores, warehouses, and potentially trucking fleets can make this decision based on optimization of costs and benefits across all of these functions. They can evaluate trade-offs between cost savings via DR program participation, higher costs of idling trucks waiting for loading, potential costs associated with delayed delivery to stores, etc.

The primary limitation of DR operation is food safety (maintaining the quality of the food, avoiding food spoilage, and avoiding reducing the life of the food).

Technology Transfer Conduits and Mechanisms

In general, the project team recommends the following technology/knowledge transfer approach for this project:

- Post a detailed project report on the Emerging Technologies Coordinating Council (ETCC) website (www.etcc-ca.com)
- Conduct and participate in webinars from CEC, EPRI, utilities, and third parties

- Engage with utility account managers:
    - Prepare a two-page fact sheet.
    - Stimulate utility consideration of a customized incentive and/or rebate program for DER at refrigerated warehouses by preparing and submitting a technology transfer form.
    - Produce short videos targeted to refrigerated warehouse operators that utility account managers can white label and use for customer education purposes, and that can also inform third-party implementers.
- Submit the technology transfer form and supporting documents to third-party implementers.
- Collaborate with groups that cater to storage and transport of food to reduce costs, including Accelerate America (http://acceleratena.com), the Air-Conditioning, Heating, and Refrigeration Institute (https://www.ahrinet.org/home), the Global Cold Chain Alliance (https://www.gcca.org/), and others.

The following presentations were submitted to several organizations:

- CEC Workshop on "Research Needs for Unlocking Flexibility in the Industrial, Agricultural, and Water Sectors" (https://www.energy.ca.gov/event/workshop/2021-06/electric-program-investment-charge-2021-2025-investment-plan-scoping-0) presentation: "Demand Response in the IAW Sectors: EPRI's ongoing CEC Project on DR in Industrial Refrigerated Warehouse (EPC-16-026)" June 21, 2021.
- Demand Response & Distributed Energy Resources Forum, presentation "Demand Responsive Technologies in the Industrial, Agriculture and Water Sectors," December 7-8, 2021.
- 2020 ETCC Webinar, presentation on "Demand Response Technology Assessments, including EPC-16-026" (https://www.etcc-ca.com/sites/default/files/u2292/etcc_tad_presentation_022620.final_.pdf) February 26, 2020.
- ATMOsphere America 2019 Conference, Industrial Refrigeration Session, presentation on "SCE Helps New Technologies in Food Processing" (https://accelerate24.news/regions/north-america/highlights-from-atmosphere-america-2019-conference/2019/) June 17, 2019, Atlanta

Fact Sheet

The fact sheet consists of the following material:

- A description of the situation: the problem and the current technology used).
- The technology: what it looks like, how it works, a schematic or photo, and how this differs from current practice.
- Advantages and opportunities: the advantages of the new or improved technology and situations where it can best be applied.
- Applications, including examples of effective applications with initial cost, and operating cost.
- Other issues, including information on ancillary issues, applicable codes and standards, and health and human performance improvement.

EPRI Activities

EPRI conducts regular meetings with key market participants that will be used to transfer the information developed in this project to these key participants.

- Twice-yearly EPRI advisory meetings and webcasts with influential utility members shape EPRI research, develop demonstration and marketing opportunities for technologies, and provide a conduit for the advisors to impart information to colleagues at their utilities.
- The EPRI Energy Efficiency and Demand Response Symposium is a forum for utility company members, manufacturers, researchers (EPRI and others), industry stakeholders, and government agencies to discuss industry changes and needed actions.

EPRI Electrification conferences explore the electrification issues, benefits, and opportunities. Attendees include utilities, industry, government, and academic leaders.

CHAPTER 6: Benefits to California

Overall Potential Benefits to Ratepayers

Implementing advances demonstrated in this project enable the following benefits:

- **Enhanced Reliability.** Project advancements and FEMS capabilities demonstrated adjustability of demand by at least 20 percent for a variety of grid use cases, including peak load reduction. The demand reduction may be higher than 20 percent for shorter-duration DR events. These services are needed to maintain high system reliability. Hence, the project supports enhanced electric service reliability for electric ratepayers.
- **Support Maintaining Lower Water Rates.** Electricity costs are significant in the sectors of water and industrial refrigeration. This project demonstrates flexible water pumping to engage in DR by adjusting pumping operations; and enables industrial refrigeration to participate as well. Consequently, plants enhance awareness of opportunities to engage in DR towards lowering electricity costs and/or earning additional revenue streams from DR program and market participation. This enables water service providers to keep rates low, which translates into maintaining lower costs to water customers, who are often also electricity ratepayers.
- **Lowers Refrigerated Product Costs.** Similarly, consumers of refrigerated products also benefit from lower product costs when cold storage facilities are able to earn additional revenue streams from participation in fast and flexible DR, and lower overall plant electricity costs.
- **Enhanced Safety.** The ability to automate demand reductions leads to increased safety of utility workers and the public, given lower throughput and demand on generation plants that reduces wear and tear on equipment, and in turn helps to extend life of equipment and reduce risk of equipment issues that could pose safety problems.

Qualitative Benefits of the Project

Qualitative benefits of the project include:

- **Greenhouse gas emission reductions** from loads providing services to displace gas turbines spinning and burning fossil fuel in the provision of reliability reserves and flexibility services.
- **More flexibly tailored DR strategies** that dynamically change based on operating conditions at the customer site.

Quantitative Estimates of Potential Benefits

Water Pumping: Demand Reduction

The peak demand from the urban water sector in California can be estimated in the following manner:

- An LBNL study [3] estimates that the total peak day average demand in 2004 is 467.6 MW by water agencies that the three California investor-owned utilities (IOUs) serve. Escalating by 2 percent per year, the estimated average peak day on-peak demand in 2020 is 642 MW. Pumping accounts for 80 percent of the overall energy use within urban water supply, based on a 1996 EPRI report [12]. By assuming that 11 percent of the demand of a water facility is attributed to water extraction pumping, a 20 percent adjustment in demand using FEMS translates to about 14.1 MW of DR potential in water pumping.
- Assuming 67 percent of the demand of a water facility is attributed to conveyance and distribution pumping, a 20 percent adjustment in demand using FEMS translates to about 86 MW.
- Consequently, there is approximately 100 MW of DR potential in water pumping in California (served by IOUs) in 2020.

Food Processing and Refrigerated Warehouses: Demand Reduction

The project team's analysis of the estimated DR potential for California refrigerated resources, described in section 5 concluded the following:

- From 2019 to 2025, the team forecasts that peak demand for California refrigerated facilities will increase by 85 percent from 100 MW to about 185 MW.
- With a historical growth rate of approximately 4 percent, in 2030 the expectation is for a peak demand from California refrigerated warehouses of 225 MW.
- Assuming that the potential for DR of warehouse refrigeration compressors is approximately 50 percent of peak load, this corresponds to a DR potential of 112 MW.
- As was the case for the Lineage site at Mira Loma, refrigeration is not the only electric load that can be leveraged for DR. The load from floor heaters and electric forklifts adds a potential of the same magnitude, so it is not unreasonable to assume a total DR potential for California refrigeration warehouses of 200 MW by 2030.
- Different loads can be leveraged for different types of DR. For example, floor heaters can respond immediately for a relatively short duration, while refrigeration loads associated with frozen rooms can last longer but require careful scheduling.
- Similar technology could be applied to the approximately 4,700 supermarkets and grocery stores in California, most of which are associated with cooled and frozen rooms, further increasing the potential for the refrigeration sector.

Estimated Quantitative Benefits to the Customer: Water

Estimated quantitative benefits to water agencies include:

- **Revenue from DR participation**. For example, consider a water agency with a peak demand of 1 MW. Using the FEMS strategy to achieve 20 percent demand reduction yields 200 kW of DR. Assuming a payment of $60/kW-year of demand reduced by participating in a DR program participating in a DR program such as DRAM (Demand Response Auction Mechanism), Capacity Bidding Program (CBP), or Aggregator Managed Portfolio (AMP), annual savings are $12,000[8].
- **Reduced electricity charges from shifting load to lower cost periods, based on forecasts of prices that are pegged to day-ahead wholesale energy market price fluctuations.** For a 1-MW plant that normally pays $100,000 per year and achieves an average of 20 percent cost savings (based on a 22.6 percent average cost savings over a three-month period in a prior EPRI study [13]), the potential electricity cost savings from load shifting to lower cost periods achieved with FEMS day-ahead price indications is approximately $10,000/year.
- **Reduced energy consumption.** In California water and wastewater sectors, about 80 percent of pumps have been equipped with variable-speed drives due to energy efficiency utility rebates, based on CPower's field experience. Consequently, a vast majority (80 percent) of pump systems in these sectors are candidates for fast and flexible DR. Based on CEC Demand Analysis Office 2012 data, domestic water pumping energy use across the three California IOUs totaled 4,812 GWh/year in 2011. Achieving a 1 percent energy consumption reduction in this sector by running variable-speed drives at lower speeds over a longer time period to pump the same amount of water, translates to a 38.5 GWh/year savings, assuming 80 percent variable-speed pump deployment[9].

Estimated Quantitative Benefits to the Customer: Refrigeration

Estimated quantitative benefits to customers include:

- Revenue from DR participation. For example, consider an industrial facility with a peak demand of 1 MW. Using the FEMS strategy to achieve 20 percent demand reduction yields 200 kW of DR. Assuming a payment of $60/kW-year of demand reduced by participating in a DR program such as DRAM, CBP, or AMP, annual savings are $12,000.
- Reduced demand charges from smoothing out customer demand peaks by running the plant over a longer period of time at lower speeds also results in savings. For a 1-MW plant that achieves a 20 percent demand reduction, the potential demand charge savings from a 200-kW reduction achieved with FEMS is approximately $19,200/year, assuming a $8/kW-month demand charge rate[10].

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[8] 200 kW * $60/kW-year = $12,000/year

[9] 4812 GWh/year * 0.8 * 0.01 = 38.5 GWh/year

[10] 200 kW * 0.2 * $8/kW-month * 12 months/year = $19,200/year

Ratepayers Economic and Societal Benefits

Ratepayers as a whole can benefit from lower retail rates due to lower wholesale cost from the broader DR participation that the decision support tool can facilitate in pumping entities. A pumping entity that uses the tool can also achieve cost savings via three possible economic scenarios: lowering demand cost itself, load shifting to lower-cost pricing periods, or participating in a pay-for-performance DR program that credits the entity for lowering demand during DR events.

- This field test project identified no cost savings from lowering demand cost because the peak power occurred outside of DR events.
- In the second cost savings scenario, the field test showed $48.11 saved on average across all DR events from load shifting to lower-cost pricing periods using CAISO LMP prices.
- Pay-for-performance contracts are not disclosed. Hence, this potential cost savings is beyond the scope of this project. However, the California ISO has instituted a cap of $1000/MWh for pay-for-performance. Ratepayers and society can benefit from lower greenhouse gas emissions due to greater grid flexibility, which allows further integration of renewables on the grid. Additionally, more generation options are presented by the greater flexibility that supports a more reliable and resilient electricity grid.

Groundwork for Future Work

The design process used in making the decision support tool can be extended to other systems and products that have inherent storage within their processes. Ultimately any device with storage that uses electricity can be leveraged for DR applications and could benefit from operational guidance on how DR may affect the system. Future studies at other pumping facilities of this nature can build off the process used in this field test. The project team addressed operator decision-making and deciphered what information is needed to make an informed decision on whether opting in is plausible for a given DR event. This information acquisition process will extend to other sites and applications. The layout and organization of the tool can also be leveraged for future applications; future studies will only need to feed new datapoints and operational constraints into the tool's computing. The information and data processing, calculating, and forecasting set the stage for future automation of such systems.

Cost/Benefit Analysis of the Current Project

Given the quantified DR potential of 90 MW from controlling water and wastewater pumping and another 130-180 MW (or 150 MW on average) from refrigeration and food processing facilities, a $3.465 million project cost yields a cost of $14.4/kW of DR potential. The resulting cost per kW is significantly below DR enabling technology incentives that the California IOUs currently pay[11].

From the DR experiments studied during this project, the compressor systems were successfully capable of 31 percent in average demand reduction in total compressor loads equivalent to 318 kW. As well, a 100 percent reduction of the floor heater loads was attained

[11] $3,465,000 / (90 MW + 150 MW) * 1 MW/1000 kW = $14.4/kW

during the DR experiments, which is equivalent to 112 kW. This was only for the 3 out of 10 rooms capable of remote monitoring and controlling of the floor heating. If additional monitoring and control systems were installed, all rooms could potentially participate in load reduction events. From these experiments, a total load reduction of 430 kW or 25 percent of total site average load was observed. While DR capacity varies significantly across resources—from less than $1/kW-year to more than $76/kW-year—the value of peak DR capacity for system operators was estimated at $54.60/kW-year for SCE in a report published in 2015 [14]. This means the value of a 430 kW demand reduction program for the Lineage site at Mira Loma would be about $23,000
per year.

Overall, the economic benefits to the customer must be greater than the cost of installation of the system, typically requiring a payback of three to five years. Thus, it is important to ensure that the technologies developed in this project are integrated within existing products, ideally in the form of standardized software solutions, where development costs can be shared by many customers and where customization costs for the site are low (on the order of a few $10,000s). This project has demonstrated that this is possible by leveraging existing products and standard protocols such as OpenADR.

CHAPTER 7:
Conclusions and Recommendations

Water Field Test Project: Conclusions

The following key conclusions stem from the water field test:

- With sufficient advance notice, water system operations personnel can adjust pumping operations by load shifting and still meet water demands with sufficient quality.
- The field test pumping station with one DR dispatchable adjustable-speed pump showed a 79-kW reduction in pump power across all eight DR events, which translates to a 30 percent average reduction in power.
- The reduction in power was fairly consistent throughout the field test, ranging from 21 percent to 32 percent. The 21 percent power reduction occurred due to the operator mistakenly reducing power 1 hour ahead of the DR event and increasing power 1 hour before the conclusion of the DR event. If this mistake had not occurred, the range of power reduction would have been 30 percent to 32 percent.
- Cal Water demonstrated high engagement by opting in to participate in all eight DR events. At the conclusion of the field test, Cal Water indicated the possibly of continuing the study with another pumping station within the broader Cal Water footprint.
- The FEMS Decision Support Tool's screen design presented a learning curve for the water system supervisor and operators. Orientation time was necessary at the beginning of the field test to help familiarize users with its graphical user interface and calculation engine. The tool experienced no notable technical problems during the course of the field test.
- The operators noted that the Decision Support Tool provided overarching guidance for their decision making and they felt that the tool was helpful. However, they did not follow the forecasted flow rates and tank levels prescriptively that were shown on the tool.
- A sizable DR market potential exists for pumping stations within Cal Water as well as other water pumping agencies, if adequately incentivized through programs and/or market incentives and operationally guided through decision-making tools like the Flexible Water Pumping Decision Support Tool.

Water Field Test Project: Recommendations

Economic savings considered in this analysis are hypothetical. Currently Cal Water is not enrolled in an electricity rate structure that financially provides incentives for DR. Thus, cost savings from the field test are expected to be negligible. Since the reduction in energy during the DR event is simply shifting the load to another time, not reducing the load itself, no energy savings are associated with reducing pump power during the DR event. As a result, no economic savings are directly correlated to energy efficiency from this field test. However, this analysis will consider three other avenues in which economic savings are possible depending on the electricity rate schedule in question.

The decision support tool can be improved in the following ways identified during the water field test:

- **Integrate the tool into the existing software platforms used by water systems personnel**. The decision support prototype was not directly installed on Cal Water's system. Users commented that integrating the screens into their existing systems (for example the PI system) would increase the likelihood of tool use.
- **Improve forecasts and default input settings for higher accuracy**. The interzonal transfer default values can impact tank level recovery, and consequently feasibility of an opt-in strategy. Currently, the metering measures of interzonal transfer are not enabled, but rely on operator user estimates and inputs. For future improvement, a better measure or forecast mechanism should be considered (such as measuring from flowrate meters and storage tank levels at transfer station). Extra data sources may come from measuring the flowrate and storage tank level of interzonal transfer station (station 058).
- **Incorporate more detailed data**. The decision support tool forecasting can be improved with more detailed information and historical data on the water system. Also, data collection methods that are able to disaggregate various data streams originating from the system are favorable for computing prediction, rather than the status quo of aggregate flow rates.

Additional recommendations include the following:

- **Extend DR within Cal Water.** The successful flexibility demonstrated at Cal Water's Zone D suggests flexibility exists within the broader Cal Water system. The project team recommends further testing of DR impact and flexibility on a broader scale at Cal Water and other water pumping entities.
- **Educate users.** Users should be educated on the tool before use. This will ultimately improve trust in the tool for decision making. A user guide could be incorporated into the tool to provide users information on parameters and inputs.
- **Extend to other DR applications.** The design process used in creating the decision support tool, gathering information and operational constraints the tool needs, and implementing the tool can be extended to other systems and products that have storage inherent in their processes. Ultimately, any device with storage that uses electricity can be leveraged for DR applications and could benefit from operational guidance (aids decision making) on how DR may affect the system.
- **Collaborate with the electric power industry to further engage customers in flexible DR.** Further case studies are recommended in collaboration with utilities to examine potential broader application of flexible DR for expansion across the water sector. It is critical to work with utilities to engage water agencies and to examine adjustments to utility programs that would remove disincentives for customers to participate in DR.

Refrigeration Field Test Project: Conclusions

Following are the key conclusions of the refrigeration field test project:

- OpenADR 2.0b works reliably. Signals could be sent and received without any inconsistencies in data.
- The Lineage plant in the SCE service territory provides sufficient power to attain approximately 30 percent up or down response. To achieve good control of the response, it is necessary to design the control sequence so that the dynamics of the plant, in combination with the response of the control system, are accounted for, potentially by using a model of the plant. It should also be noted that project power was controlled indirectly in this project by altering the frozen room temperature setpoint. However, more sophisticated, modern control systems could allow direct intervention of the power of the compressors.
- Many plants use electric resistance floor heating to prevent freezing of the ground under the plant. Floor heaters respond instantaneously, so they can be used in combination with compressors to provide a combination of speed and flexibility.
- Processes in a refrigeration plant are many and interact in complex ways, which may disrupt the outcome of a DR event. Local experience at the plant is needed when designing DR control sequences, that may be plant-specific.
- Care is needed when designing DR event schedules. Incorrectly designed schedules can lead to low round-trip efficiency between power-up (charging of the thermal "battery") and power-down (discharging of the thermal "battery"). Low round-trip efficiency can be due to a variety of factors. The plant is already optimized to operate under certain conditions and is quite efficient, without much "room" for changing setpoints. Ramping up the compressors may impact the efficiency for pre-cooling during the events. Additional cooling may also trigger defrost cycles, which can further reduce compressor efficiency. In addition to this, the refrigeration plant is not completely insulated and sealed, and lower room temperatures can result in additional energy losses.
- Controlling the power is not straightforward. Some existing sophisticated control systems at refrigeration plants are already performing an optimization calculation to realize the highest possible benefit from existing real-time pricing tariffs, while ensuring refrigerated product quality. Some of these controllers use complex real-time pricing forecasting algorithms to determine when to curtail refrigeration systems based on the present and future forecasted electricity prices and length of time that the food can "drift" with the refrigeration system off. When the additional opportunity of DR is considered for these plants, the DR component (for example in the form of DR pricing, DR incentives, or noncompliance penalties) must be formulated into the optimization algorithm.
- There are many operational constraints. Since the products in the refrigeration warehouse are temperature sensitive, the primary constraint is that the DR events do not lead to a temperature drift beyond the acceptable range for the products.
- DR must be integrated with overall control to ensure robust and economic operation.

- The numerical model of heat transfer processes provided insight into the observed system behavior, which is a consequence of heat transfer processes between various system components and the dynamics of the PID controller.
- The project improved understanding of load disaggregation in refrigeration plants. The refrigeration plant was perceived to be the largest load within the plant, but accounted for less than 50 percent of the total site power demand. Various other loads in the plant have the potential for flexible DR without as much complexity, such as floor heating.

Refrigeration Field Test Project: Recommendations

Conduct Several Additional Field Tests in California

The facility in this project uses a sophisticated control system to optimize energy use with respect to prices. California has a large number of refrigerated warehouses, with varying degrees of sophistication, and it is important to demonstrate how OpenADR 2.0b can enable automated DR in several such facilities, by integrating DR procedures with existing plant management systems where possible. A small field test project could prove concept applicability to several facilities. This would help convince warehouse operators to reach out to energy service providers to launch programs that would support the grid, while reducing warehouse operating costs.

New DR programs are evolving in California. The California Public Utility Commission is exploring price-based signals via the UNIfied, universal, Dynamic Economic signal. The CEC is developing the Market Informed Demand Automation Server to send market-based pricing signals. Such signals could be tested to determine whether they provide value to refrigerated warehouses and the grid. In addition to warehouse compressor systems, the field test project could explore the DR potential of electric forklift trucks and electric resistance heating:

- **Concrete floor heaters**. If moisture under the concrete slab of the refrigeration plant freezes and then melts repeatedly, expansion and contraction cycles eventually cause concrete slab buckling. To maintain this water in liquid form, most refrigeration plants employ electric resistance heaters or glycol systems under the concrete slab. Because of the high thermal mass of the concrete slab, temperature changes are slow, so that floor heaters provide an additional DR opportunity, with fast reaction time, that can be combined with compressor load.
- **Electric forklift truck charging**. Currently, electric forklift trucks are charged on an as-needed basis, or during times of low activity. Activities are ongoing to track the use of the trucks, with the ultimate goal of actively managing and optimizing charging. DR should be integrated with charging fleet optimization systems when these are present.

Electric Refrigeration Systems on Transport Trucks

In a broader perspective, the entire food and beverage "cold chain" can be examined. This can include freezing the food in the factory, transporting it in a refrigerated truck to a refrigerated warehouse, storing it in the warehouse, and then transporting it by refrigerated truck to supermarkets. Today, most refrigerated trucks use diesel-powered cooling for the food and beverages they transport.

Transport of food and beverages using electric-powered cooling units on the trucks has several potential benefits, including improved energy efficiency, and reduced emissions and hence decarbonization, depending on the “fuel” used to generate the electricity. Cost savings are also possible, depending on the local prices of electricity and diesel fuel, the capital and maintenance costs of the truck-mounted cooling units, and other factors. Refrigerated warehouses could take advantage of charging these trucks when parked for an extended period. These trucks could be charged when low-cost electricity is plentiful. However, for such a project, standardization of charging ports is required.

Technology Transfer in California and Other Parts of the United States

The team recommends educating a wide variety of stakeholders—warehouse operators, energy service providers, distribution system operators, and energy officials in the State and Federal Government—on this project’s success using various modes of technology transfer.

LIST OF ACRONYMS

Term	Definition
ACEEE	American Council for an Energy-Efficient Economy
ADR	automated demand response
AMP	aggregator managed portfolio
API	application programming interface
ASHRAE	American Society of Heating, Refrigerating and Air-Conditioning Engineers
AWE	alerts, warnings and emergencies
AWWA	American Water Works Association
CAISO	California Independent System Operator
CBP	capacity bidding program
CEC	California Energy Commission
CPUC	California Public Utility Commission
CSP	curtailment service provider
DAM	day-ahead market
DER	distributed energy resource
DR	demand response
DRAM	demand response auction mechanism
DRAS	demand response automation server
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESDER	Energy Storage and Distributed Energy Resources
ET	emerging technology
ETCC	Emerging Technologies Coordinating Center
EV	evaporator
FEMS	Flexible Energy Management System
GPM	gallons per minute
GWh	gigawatt-hours
IEEE	Institute of Electrical and Electronics Engineers
IoT	internet of things

Term	Definition
IOU	investor-owned utility
ISO	independent system operator
kW	kilowatt
kWh	kilowatt-hours
LBNL	Lawrence Berkeley National Laboratory
LMP	locational marginal price (or pricing)
M&V	measurement and verification
MAPE	mean absolute percentage error
MIDAS	Market Informed Demand Automation Server
MW	megawatt
NOAA	National Oceanic and Atmospheric Administration
OpenADR	Open Automated Demand Response
PID	proportional-integral-derivative
PLC	programmable logic controller
RMSPE	root mean square percentage error
RPMS	refrigeration plant management system
RTP	real-time pricing
SCADA	supervisory control and data acquisition
SCE	Southern California Edison
TOU	time-of-use
UC	University of California
UNIDE	UNIfied, universal, Dynamic Economic
USDA	U.S. Department of Agriculture
UTC	coordinated universal time
VEN	virtual end node
VFD	variable-frequency drive
VOC	volatile organic compound
VTN	virtual top node
WFM	Water Research Foundation
WMS	water management system

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APPENDIX A: DR Opportunities at Water Pumping Facilities in California

Water pumping can be enabled to support grid needs, including renewable integration, by leveraging pumping equipment in the water and wastewater sectors. The taxonomy described in this appendix is used to explain the water sector and opportunity presented for flexible water pumping.

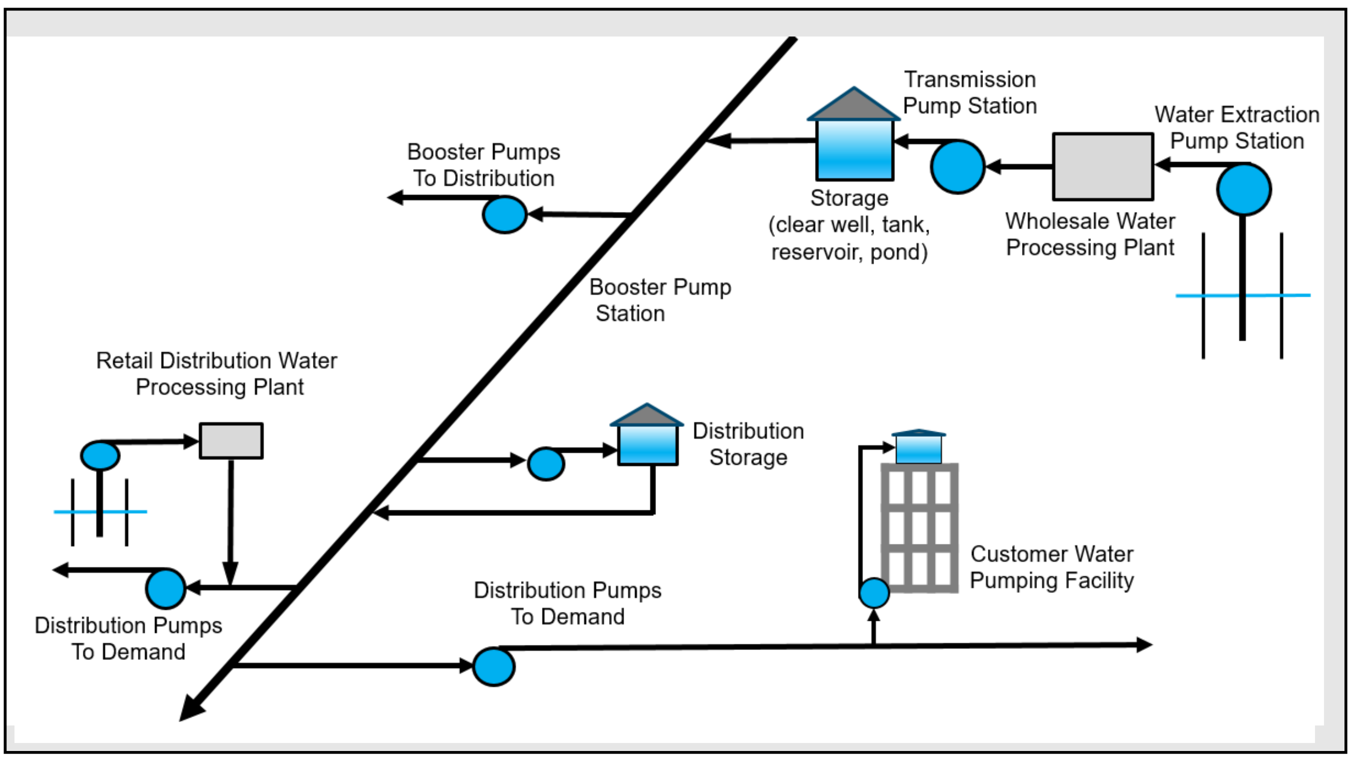
Water Sector Taxonomy

The water sector involves different pump types and plant or station types, which together comprise equipment types. The plant or station types are identified, and Figure A-1 depicts their relationships.

Terminology

- A pump station is a location with one or more pumps.
- A water processing plant is a facility with a water treatment process.
- A plant is a location that facilitates an industrial process.

Figure A-1: Taxonomy of the Water Sector Plant and Station Types



Source: EPRI

Plant and Station Types

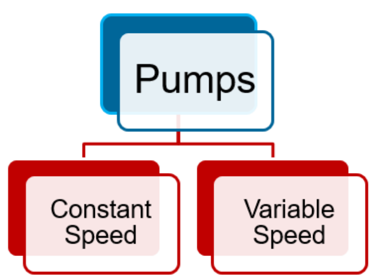
- A water extraction pump station is a location with one or more pumps that extract water from a source (for example groundwater or surface water).
- A wholesale water processing plant is a water treatment facility of a water wholesaler.
- A transmission pump station is a location with one or more pumps that transmit water to large water customers (such as municipalities).
- A booster pump station is a location with one or more pumps that increase water pressure along a pipeline.
- A distribution storage station is a location that stores water.
- A retail distribution water processing plant is a water treatment facility of a water retailer.
- A distribution pump station is a location with one or more pumps that distribute water to end customers.
- A customer water pumping facility is a commercial facility with water pumping operations that serve customer water demands in the building.

Pump Types

- A constant-speed pump operates only at constant speed.
- A variable-speed pump is an adjustable pump system that can operate at varying speeds.

Figure A-2 shows that the taxonomy for flexible water pumping includes two mutually exclusive classifications of pump types: constant speed, and variable speed. Although energy characteristics differ by pump technology type (such as centrifugal, positive displacement, etc.), this classification of pump types suffices for the purposes of flexible water pumping strategy development.

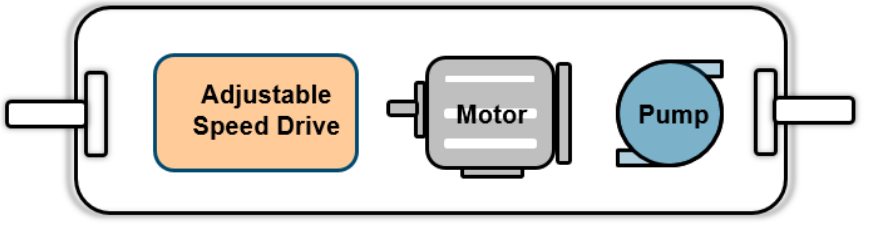
Figure A-2: Classification of Pump Types



Source: EPRI

Pump technology types are constant speed or variable speed, depending on whether equipped with a variable frequency drive (VFD). Any pump technology type can be equipment with a VFD to operate at variable speed. If equipped with a VFD, the pump system is called an adjustable-speed pump (ASP). Figure A-3 depicts this arrangement.

Figure A-3: Components of an Adjustable-Speed Pump System



Source: EPRI

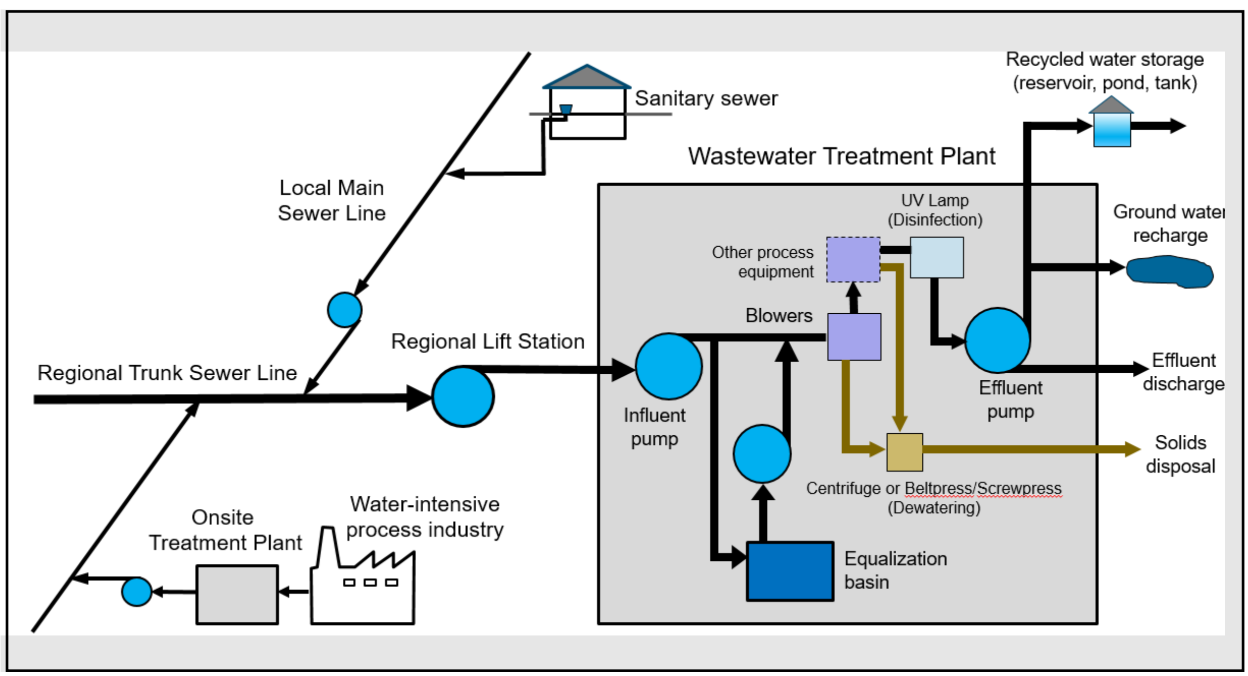
Flexible Water Pumping Opportunity

The described taxonomy enables systematic identification of pumping equipment in different plant or station types to consider in flexible water pumping control strategies. In particular, water extraction pumps present excellent opportunities for flexible water pumping, especially in stations with redundancy in pumping equipment and/or ample water storage capacity. For constant-speed pumps, the strategy is to turn off/on pumps in coordination with system or market needs. For variable-speed pumps, viable strategies include adjusting pumping speed to decrease power consumption during system peak periods, or increasing power consumption during periods of over-generation in the power system. Speed adjustments depend on available pump speed settings accessible by the water management system.

Wastewater Sector Taxonomy

Figure A-4 shows that the wastewater sector involves different pump types and plant or station types, which together comprise an equipment type. The plant or station types are identified in the figure.

Figure A-4: Taxonomy of the Wastewater Sector Plant and Station Types



Source: EPRI

Plant and Station Types

- A wastewater treatment plant is a wastewater processing facility that removes waste and solids from incoming influent water to produce effluent water within the standards of governing organizations (for example federal, state, and local regulations). Major pumping equipment found in wastewater treatment plants include:
  - The influent pump controls the flow of water into a treatment plant.
  - The storage pump controls the flow of water redirected for storage within a treatment facility (such as equalization basin).
  - The effluent pump controls the flow of treated water discharged out of a treatment plant.
- A regional lift station is a location with one or more pumps that elevate wastewater prior to entry into a treatment plant.
- A local main sewer pump station is a location with one or more pumps that direct sewer water to continue to flow into a regional trunk sewer line.
- An onsite treatment plant is an industrial facility that processes wastewater generated onsite by an industrial process before discharge into the public sewer system.
- A recycled water storage station is a location that stores recycled water.

Flexible Wastewater Pumping Opportunity

The described taxonomy enables systematic identification of pumping equipment in different plant or station types to consider in flexible wastewater pumping strategies. In particular, influent and effluent pumps present excellent opportunities for flexible wastewater pumping, especially in stations with redundancy in pumping equipment and/or ample wastewater storage capacity. For constant-speed pumps, a strategy is to turn off/on pumps in coordination with system or market needs. For variable-speed pumps, strategies include adjusting pumping speed, based on available speed settings configured for the pump accessible by the wastewater management system.

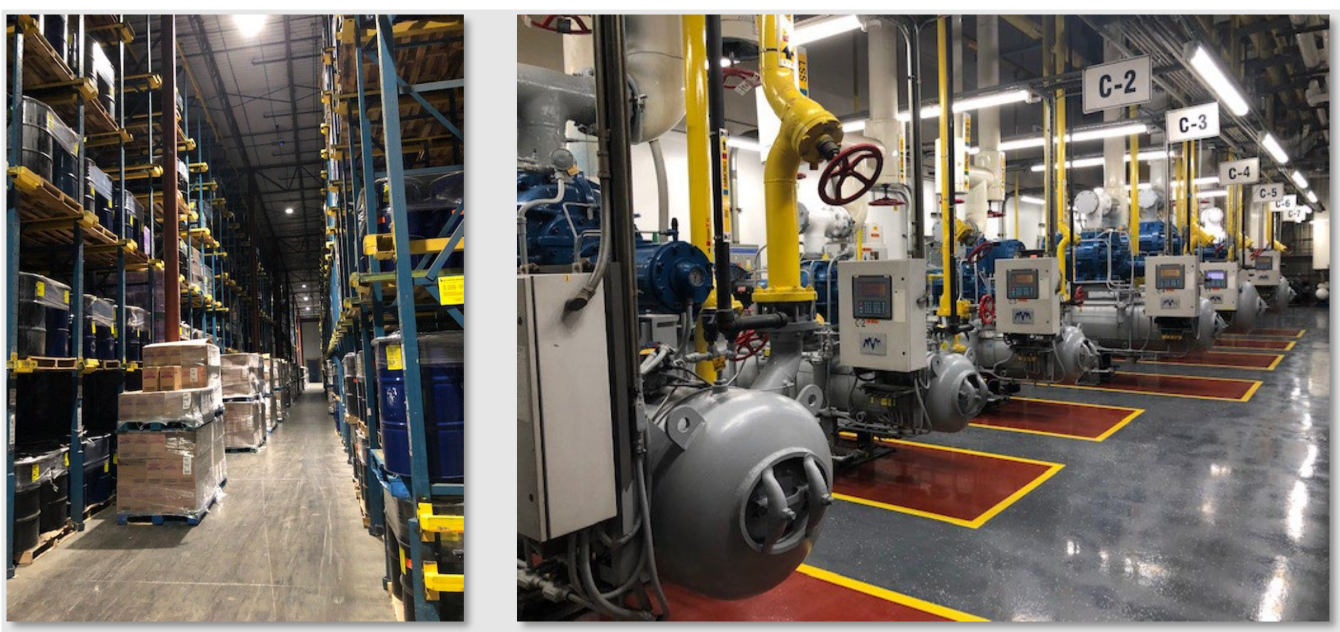
APPENDIX B: DR Opportunities at Refrigerated Facilities in California

This appendix describes DR opportunities at industrial refrigerated facilities in California, including the characteristics of refrigerated warehouses, the relationship between refrigerated product temperature and power demand, refrigerated warehouse control systems, and the DR economic proposition.

Overview

Industrial refrigerated warehouses are excellent candidates for implementing DR strategies, since they consume a substantial amount of electricity. Figure B-1 shows interior views of industrial refrigeration facilities. In a U.S. Department of Agriculture study, as of 2019, there are 389 million cubic feet (11 million cubic meter) of gross refrigerated warehouse space in California [7]. Assuming an average of 60 tons of refrigeration capacity per million cubic feet (2100 tons per million cubic meter) [8] and an average of 1.3-2 kW of electric power per ton of refrigeration capacity, this translates to approximately 50 MW of total refrigeration electric demand for the refrigerated warehouse inventory in California.[12]

Figure B-1: Interior Photos of Industrial Refrigeration Warehouses



Photos of the frozen room (left) and compressor room (right) inside the refrigeration site.

Source: EPRI

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[12] 389 million cubic feet * 60 tons of refrigeration/million cubic foot * 2 kW electricity/ton refrigeration = 46,680 kW

Refrigerated warehouses exhibit a unique combination of factors that are favorable for DR:

- Refrigeration loads account for a sizeable portion of the facilities' total energy usage.
- Their use is often greatest during utility peak periods.
- The thermal mass of the stored product in the insulated spaces can often tolerate reduced cooling capacity for a few hours when needed.
- This same thermal mass can also consume surplus grid capacity when events of over-generation occur during the spring and fall and the warehouse is below its peak capacity at mild ambient conditions.
- System DR capability is fast and flexible, potentially increasing or decreasing power several times a day and doing this relatively quickly.

Refrigerated warehouses can potentially provide similar operating characteristics as a battery energy storage system, with energy discharge in the form of load curtailment and energy charging in the form of increasing refrigeration power loads. In a sense, a refrigerated warehouse is a thermal battery energy storage system that stores energy in the form of frozen products.

Characteristics of Refrigerated Warehouses

The two major categories of refrigerated storage facilities are coolers that store products at temperatures above 32°F (0°C), and freezers that store products at temperatures less than 32°F (0°C). Customer contracts typically specify temperature settings. Refrigerated warehouses typically provide the following services:

- Blast freezers provide a high capacity for fast cooling, which reduces food damage
- Carefully monitored, temperature-controlled warehouse space includes freezer rooms that provide long-term storage of packaged foods. These rooms ensure that the temperature remains below a specific setpoint, which is typically 0°F (-18°C).
- High-pressure processing is designed to kill vegetative flora in foods by rupturing cell membranes.

Refrigerated warehouse facilities are classified as public warehouses, which store food for clients at a certain price; and private warehouses, which typically encompass the role of producer, manufacturer, packager, and refrigerator for products. Semi-private facilities usually include a private warehouse section with additional space for public storage. Some warehouses have expanded their capabilities for revenue purposes and also operate as distribution centers [15]. They can include farms, fruit, and vegetable freezing facilities, storage facilities for processed food products, and dairy and wine processors. The energy loads in these facilities vary due to the varying seasonal storage of products. However, energy loads for all refrigerated warehouse types typically peak during summer months when agricultural facilities face heavy demands and refrigeration systems must work harder to compensate for warmer weather [16]. The ability to change warehouse product temperatures by even as little as 2°F (1°C) could result in significant DR opportunity [17].

Control systems in these facilities must ensure personnel safety, product quality, and regulatory compliance before, during, and after DR events. An integrated control system is the key to enabling refrigerated warehouses to participate in DR activities. In recent decades, refrigeration control systems have evolved significantly. However, due to the long lifespan of most refrigerated facilities, arrangement of several vintages of equipment and controls in different configurations at a single facility is not uncommon.

Previous studies have extensively surveyed refrigerated facilities in California to understand their potential for load shedding. A 2012 Lawrence Berkeley National Laboratory (LBNL) report surveyed and categorized California refrigerated facilities by their function, refrigeration system type, and control type [18].

Table B-1 shows the categories of the 294 facilities evaluated in the study to develop the landscape of industrial refrigerated facility controls in California. Facility locations ranged the entire length of the state, with expected concentrations in the San Joaquin and Salinas valleys, as well as the major metropolitan areas surrounding San Diego, Los Angeles, and San Francisco.

Of the 294 facilities, nearly 61 percent (179) used an integrated control system[13] that could provide a single interface point to the refrigeration system for DR activities (with appropriate programming changes and control extensions). A majority (59 percent or 106) of these integrated systems utilized a non-proprietary control platform[14]. Non-proprietary control systems increase the potential pool of controls providers that a facility could use to make programming additions required to implement DR or auto-DR.

The LBNL report also evaluated the role of controls on a refrigeration system's ability to load shed. Table B-2 from the LBNL report shows the relative DR potential of facilities with respect to the type of system control. The LBNL report concluded that an integrated control system, either proprietary or non-proprietary, was essentially a prerequisite for full DR participation.

[13] The LBNL report defines an "integrated control system" as a system that requires one point of connection with the automated DR (Auto-DR) signal, compared to a standalone control system that requires an Auto-DR request to be sent to multiple devices in the same facility.

[14] The LBNL report does not further define the difference between proprietary and non-proprietary systems, nor does it provide examples of non-proprietary platforms.

Table B-1: Summary of Facility Control Systems for Refrigerated Facilities in California

Control Type	Ag Processors	Food Processors	Warehouses	Beverage Producers	Total
Integrated Control Systems (Totals)	**50**	**46**	**69**	**14**	**179**
Nonproprietary Integrated Controls	28	27	42	9	106
Proprietary Integrated Controls	22	19	27	5	73
Standalone Control Systems (Totals)	**29**	**50**	**30**	**6**	**115**
Partial PLC/Electromechanical Controls	5	11	9	3	28
Basic Nonintegrated Controls	21	35	20	3	79
Mix of Controls	3	4	1	0	8
Overall Totals	**79**	**96**	**99**	**20**	**294**

Source: LBNL

Table B-2: Summary of the Relative DR Potential of Industrial Refrigerated Facilities

Control Type	Ag Processors	Food Processors	Warehouses	Beverage Producers
Nonproprietary Integrated Controls	9	9	10	7
Proprietary Integrated Controls	8	8	9	6
Partial PLC/Electromechanical Controls	6	6	7	3
Basic Nonintegrated Controls	3	3	4	1
Mix of Controls	4	4	5	2

Low	1	2	3	4	5	6	7	8	9	10	High

Source: LBNL

Refrigerated Product Temperature and Power Demand

The primary objective of the refrigerated warehouse is to maintain the desired temperature of food products stored in the warehouse. Since preservation of the products placed within the refrigeration warehouse is temperature sensitive, it is important that the DR events do not lead to a temperature drift beyond the acceptable range for the products.

At the Lineage facility in Mira Loma (the subject of this document), products are refrigerated at two levels: fresh and frozen. The acceptable storage temperature, or range of operating temperature, of different fresh products/dairy varies from 18°F (-8°C) to 35°F (2°C). Most frozen products require similar operating temperatures, but some products such as ice cream require a much lower temperature than other frozen products. Also, the acceptable temperature range for fresh produce/dairy storage may be generally narrower than the acceptable temperature range of frozen products, which may be wider. Additionally, the thermal mass of the fresh products is somewhat smaller than the thermal mass of the frozen products. Therefore, the frozen products can provide more DR for longer durations than the fresh produce/dairy.

Maintaining acceptable temperature conditions of the produce/dairy and product is necessary at all times in a refrigerated warehouse. However, due to the high thermal mass of the product, if the refrigeration is turned off for some time, the refrigerated temperature can float/coast for some time without impacting the produce/dairy and product. In fact, the refrigeration system is routinely turned off daily—and multiple times daily for frozen products storage—and heat is applied to the cooling coil to defrost the refrigeration equipment with negligible impact to the refrigerated produce/dairy and frozen products. In a DR event, the length of time that the refrigeration system is not operating could be longer than the duration of a defrost event.

Control Systems and the DR Economic Proposition

Another complexity involves the fact that some existing sophisticated control systems at refrigeration plants are already performing an optimization calculation to realize the highest possible benefit from existing real-time pricing tariffs, while ensuring refrigerated product quality. Some of these controllers use complex real-time pricing forecasting algorithms to determine when to curtail refrigeration systems based on the present and future forecasted electricity prices and length of time that the food can "drift" with the refrigeration system off.

When the additional opportunity of DR is considered for these plants, these sophisticated controllers must now solve an even more complex optimization problem, which is to incorporate the DR component (e.g., in the form of DR pricing, DR incentives, or noncompliance penalties) into its optimization for real-time pricing. One aspect of this complex optimization is modeling how the thermal mass of the refrigerated or frozen food responds (taking into account its geometry, temperature differences, and other heat transfer factors) over time when the refrigeration is turned on and off. (The project team conducted this modeling as part of this effort; Appendix H describes this modeling effort.)

Electric resistance concrete slab heaters, often used in refrigerated warehouses to prevent damage from subsurface water freezing, offer an additional opportunity for DR. Indeed, they are active and significant participants in the dynamics of the warehouse thermal system. System optimization services already use physical models of the warehouse, and could incorporate the floor thermal mass and associated heaters. A characteristic of electric resistance floor heaters is that they can respond immediately. This characteristic could be used to improve the performance of the DR control, increasing both capacity and speed of response.

Forklift truck charging, if managed, could provide a DR opportunity of comparable capacity to refrigeration compressors and electric floor heaters. For this to occur, a fleet charging optimization system must be in place. Activities to this end are already taking place at the Mira Loma site. Because charging is only loosely coupled to the thermal dynamics of the warehouse, DR that leverages forklift charging could be managed separately from the thermal systems.

Other DR opportunities are emerging that can leverage transportation systems that interact with the plant, namely electric truck refrigerators, and in the future, truck battery charging itself, managed through charging stations located at the plant.

APPENDIX C: Novel Developments and Standards Used in this Project

This appendix summarized novel developments used in this project, including the Flexible Energy Management System and refrigeration optimization system. This appendix also summarizes the important standard used in the refrigeration portion of this project: OpenADR.

Flexible Energy Management System (FEMS) Architecture

Figure C-1 shows that the Flexible Energy Management System (FEMS) used in this project integrates sub-metered pump and refrigeration electricity usage information with process controls information (such as water flow rates and storage levels in the water sector; product temperature in the refrigeration sector), available through SCADA systems, to enable pump and refrigeration system control for fast and flexible DR.

Figure C-1: Systems Architecture of the Flexible Energy Management System for Water Pumping and Refrigeration DR

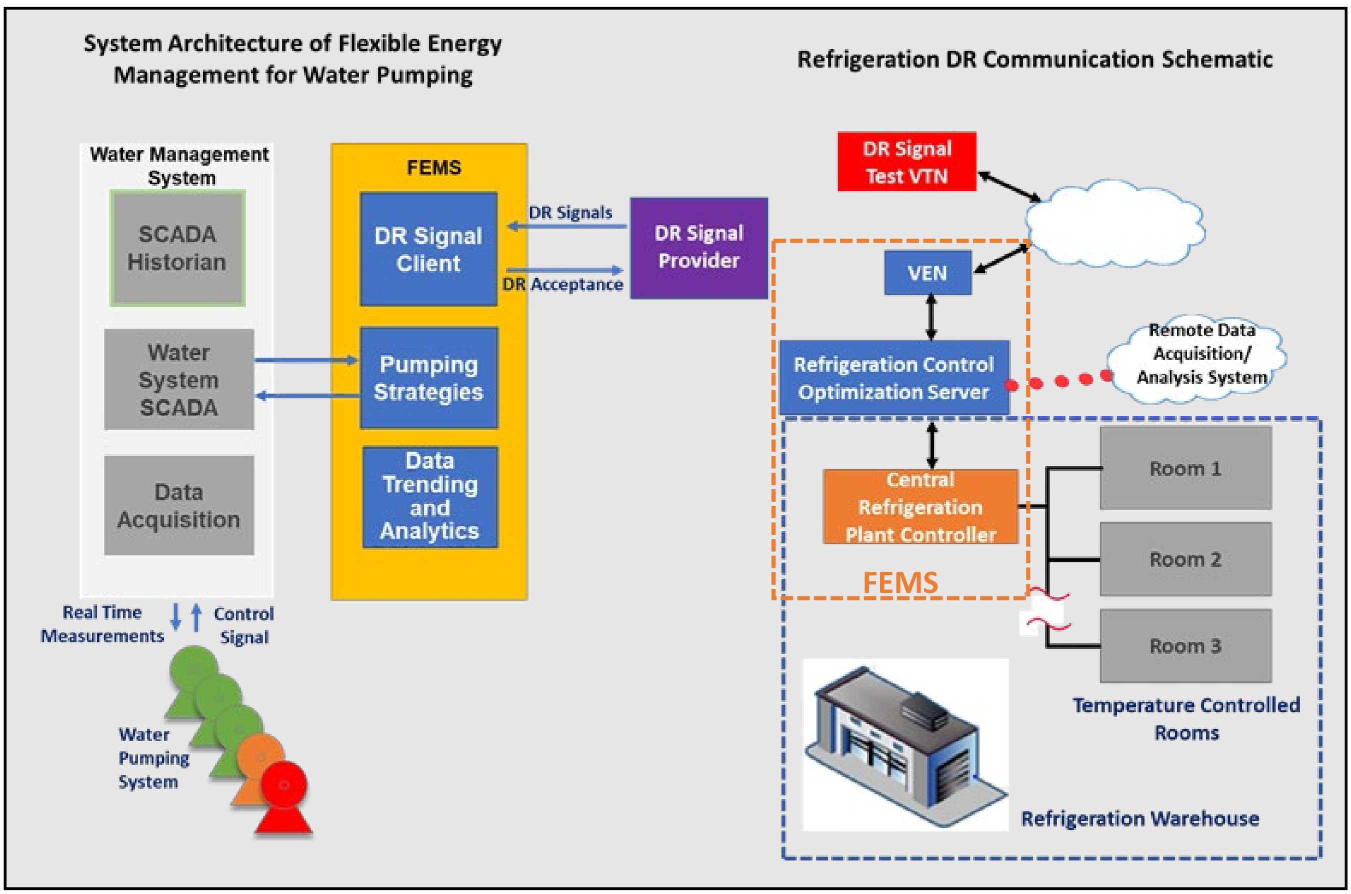


Diagram showing the systems architecture of the Flexible Energy Management System for Water Pumping and Refrigeration DR.

Source: EPRI

Additional FEMS capabilities include:

- Integrated pump power usage information (for example kW) alongside process controls information (such as pressure, flow, temperature).
- Tracking and trending historical information to inform DR availability, capability, and past performance.
- Ability to process, interpret, and respond to DR signals.

Key outputs from the FEMS are communicated back to the DR signal provider to inform the scheduling of DR resources in the California market context. Data analytics are employed to inform the development of control strategies respectful of hydraulic constraints of the connected water system and nearby pumps, and storage temperatures of refrigerated and frozen products in the warehouse.

OpenADR

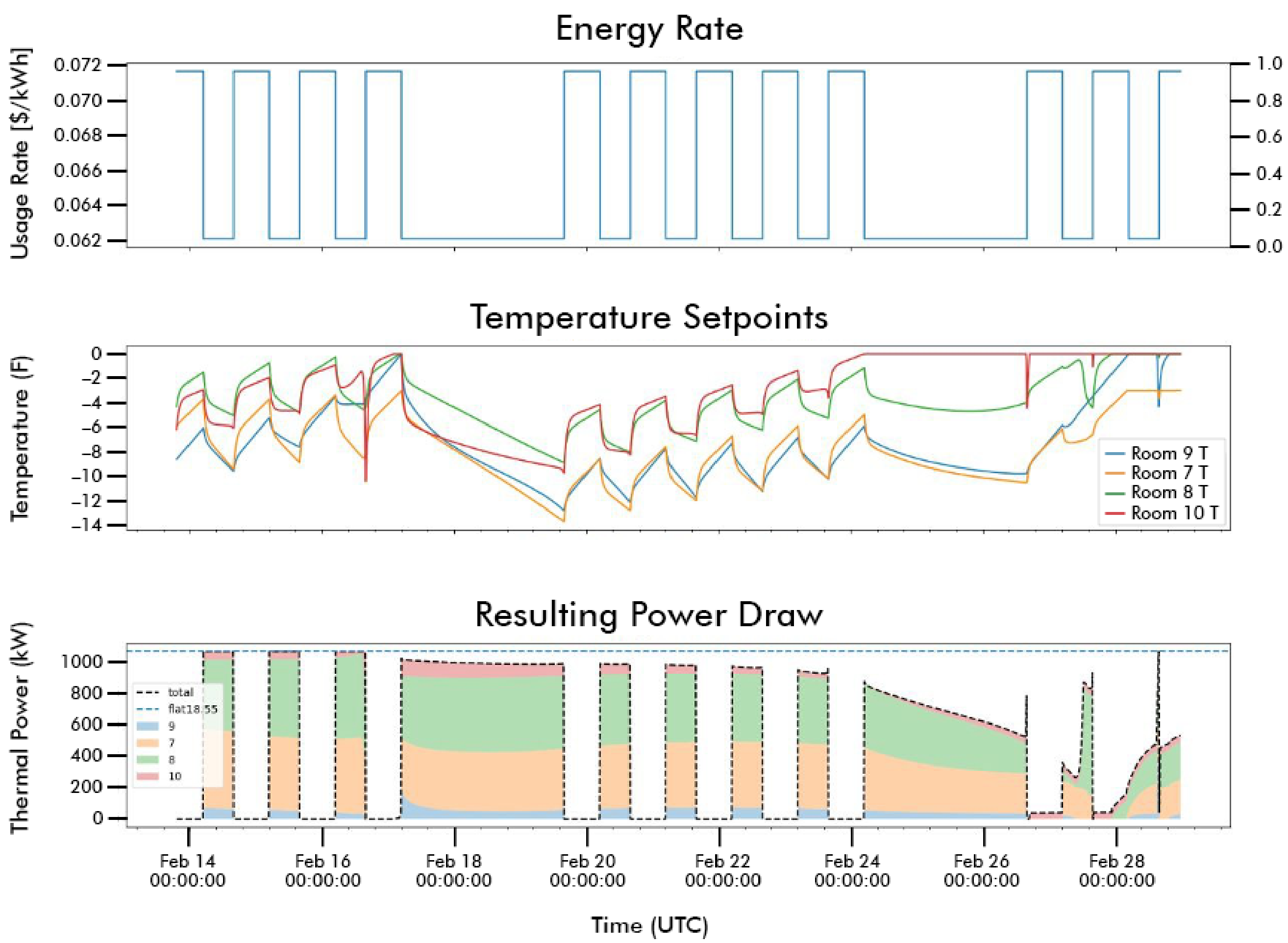
OpenADR is an open, two-way information exchange model and global Smart Grid standard that has been in use since 2009. OpenADR standardizes the message format used for automated DR and distributed energy resource management so that dynamic price and reliability signals can be exchanged in a uniform and interoperable fashion among utilities, independent system operators (ISOs), and energy management and control systems. Industry stakeholders formed the OpenADR Alliance (https://www.openadr.org/) in 2010 to support the development, testing, and deployment of commercial OpenADR and facilitate its acceleration and widespread adoption. The OpenADR Alliance has certified over 100 devices as conforming with the OpenADR 2.0 specification. Led by the California utilities, testing and adoption of OpenADR has been underway for several years.

The project team used the OpenADR 2.0b communications protocol for field testing fast DR and select forms of flexible DR, such as balancing energy and ramping energy. Although OpenADR 2.0a has been widely employed for DR signaling, OpenADR 2.0b includes a flexible reporting (feedback) mechanism for past, current, and future data reports. This reporting can be used to determine the current status of equipment operation, current electric power draw, and DR verification comparing electric power before and after DR signals are sent. The 2.0b specification also includes expanded signal types (for example LOAD_CONTROL, ELECTRICITY_PRICE, LOAD_DISPATCH) in addition to the sole SIMPLE signal for 2.0a that only allows four discrete values (0, 1, 2 and 3). The 2.0b enhancements to the OpenADR specification enable transmission system operators, distribution system operators, and aggregators to better monitor curtailment or load-up levels among DR event participants. OpenADR 2.0b has yet to be employed by water pumping or refrigeration facilities to enable fast and flexible DR. This project was among the first to field test the technology for such use cases.

Refrigeration Optimization System

The basic concept of a refrigeration optimization system is to take advantage of a detailed thermal model of the plant to predict how food product temperatures react to changes in control settings. Based on these models, control settings are adjusted so that energy-consuming equipment (such as chiller compressors or evaporator fans) operates when energy cost is lower, while at the same time ensuring that food product temperatures remain within the required range. Figure C-2 shows a sample optimized operating schedule. During periods with high energy prices, setpoints for individual rooms are increased so that that compressor operation ceases or is minimized. Forecasting of energy prices also allows optimized schedules to be implemented over long periods of time. For example, the temperature setpoint can be reduced during a long period of low energy prices to enable successive periods of reduced compressor operation when recovery during the periods is not practical. The optimization algorithm can use real-time energy prices, such as the ones available by direct wholesale access.

Figure C-2: Operations Schedule Optimization Example



The diagram shows example optimization and operations schedule for the Lineage refrigeration plant, using the energy price as an input to the optimization process. Note that temperature setpoints are controlled to eliminate energy use during peak energy prices.

Source: CrossnoKaye

A specified level of demand reduction or increase using this framework can be obtained in a number of ways. For example, the energy rate (either demand or energy price) can be altered during the DR event, or constraints on the optimization function can be adjusted. The scheduling optimization software used in this project is an early version, with a "hardwired" optimization algorithm that did not allow for easy implementation of such modifications. Rather than alter the production software, plant managers opted to run the DR events from a secondary control server, with manually implemented temperature setpoint schedules.

For the purposes of the present field test project, the team removed the production server from the control loop, and substituted it with a non-optimizing server that implemented pre-defined room temperature setpoint schedules. The remainder of the controls loop—including connection to the plant embedded controls, energy price information, and VTN servers—remained unchanged. The architecture of the control system is discussed later in this report.

Looking to the Future

The CrossnoKaye optimization framework currently used to minimize energy costs could easily be adapted to incorporate the value of DR, in a number of ways. One would be to incorporate economic benefits of DR into the energy price. The system would then adjust temperature setpoints to reflect this. If the economic benefit of participating in DR is high enough, then the system will adapt the temperature setpoint schedules accordingly. This would provide maximum economic benefit for the customer, but would not guarantee a certain level of response. An alternative method could be to impose constraints driven by the requested DR on the optimization problem. This would guarantee the desired response, but the strategy may not produce the lowest possible price for the customer.

As discussed in this report, the floor heaters are not traditionally considered in cost minimization, because they are controlled independently. However, floor heaters are just another component of the thermal system, and could easily be incorporated in the model, provided that they are controlled by the same controller that operates the compressors. The advantage of using floor heaters would be twofold: added capacity, and faster response.

An additional resource is provided by the forklift charging systems. Under the assumption that the position and state of charge of individual forklift trucks is known, and coordinated with the food delivery system, it could be possible to schedule charging of individual forklift trucks, so that collectively they could participate in DR events.

APPENDIX D: Refrigeration Control System: Sequence of Events to Respond to a DR Signal

This appendix describes the sequence of events used to respond to a DR signal in the refrigeration control system.

The OpenADR 2.0b Profile Specification (http://www.openadr.org/specification) (known as "2.0b") builds upon the OpenADR 2.0a Profile Specification released in August 2012. It adds enhanced DR event and price scheduling, robust reporting services, and a number of operational and administrative updates to simplify customer participation management and system registration. The 2.0b enhancements enable independent system operators, utilities, and aggregators to better monitor curtailment levels among DR event participants. For this project, the team leveraged these features as follows:

1. The team used the enhanced communications features to communicate the level and duration of the DR event.
2. The team used the reporting features to provide feedback to the VTN, in the form of the combined demand for all the compressors in the system at a regular interval of 5 minutes.

Figure D-1 shows how the DR signals from the EPRI virtual top node (VTN) go to the MelRok Touch Gateway. Following is the sequence of events that takes place to respond to a DR signal:

1. Event behavior configuration occurs in the MelRok cloud (portal).
2. EPRI hosts the DR Automation Server (DRAS).
3. The automated DR (ADR) event is setup and configured on the DRAS. (Previously, the DRAS installed a matching certificate to allow communication with the Touch gateway.)
4. The CrossnoKaye system optimization service hosts a restful service to allow the Touch Gateway to send the DR signal.
5. When the event is configured on the DRAS, the Touch Gateway downloads and configures the event schedule.
6. When the event is scheduled to start:
    a) The Touch Gateway calls the application programming interface (API) to notify the CrossnoKaye service that the event has started.
    b) The Touch Gateway triggers the agreed-upon sequence of operations.
    c) The CrossnoKaye system implements a sequence of operations
7. During the event:
    a) The Touch Gateway calls the API to obtain operational data from the CrossnoKaye service.
    b) The Touch Gateway relays information to the EPRI DRAS via OpenADR 2.0b using the pre-determined data structure.

8. When the event is finished:
   a) The Touch Gateway triggers the agreed-upon sequence of operations to return to the initial state.
   b) The Touch Gateway calls the API to notify the CrossnoKaye service that the event has been completed.

Figure D-1: Communication Architecture for OpenADR 2.0b Implementation

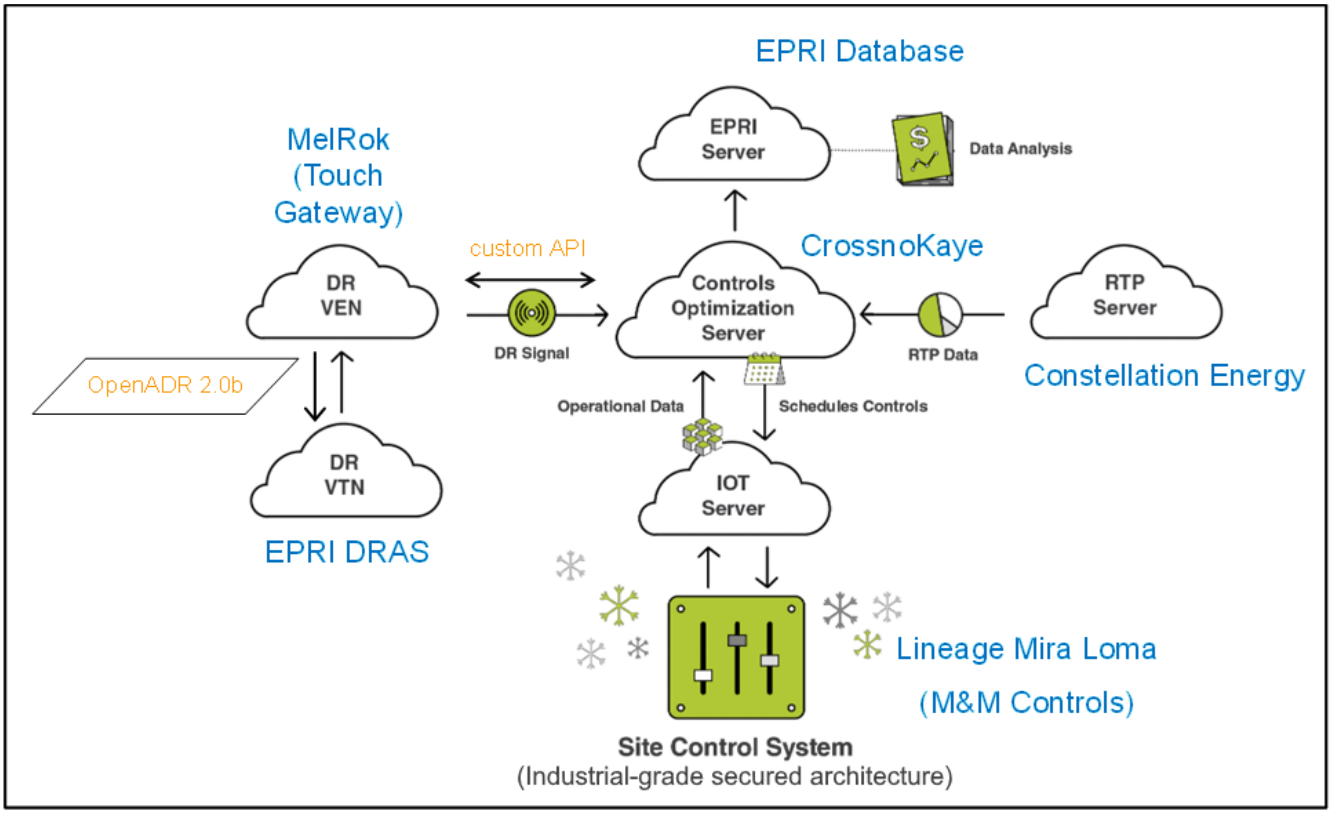


Diagram showing the communication architecture for implementing OpenADR 2.0b on the Lineage refrigeration plant with process optimization

Source: EPRI

APPENDIX E:
Flexible Water Pumping Field Test: Decision Support Tool

This appendix describes the decision support tool that the water pumping project team designed, implemented, and field tested.

Overview

The primary innovation of the water pumping field test was the design, implementation, and field test of a decision support tool designed to engage water system management supervisors and operators in DR. The hypothesis of this work is that it is possible, through data analysis, to provide accessible and actionable information to system operators that enables them to decide whether to opt-in to a specific DR event. From a water system operator's point of view, the ability to engage in a DR event depends on whether, at any point during the event, there is likelihood of an excessively low tank level or of excessive residence time of water in a tank. In this context, the project team developed a flexible water pumping decision support tool to support the Cal Water operations team in understanding operational constraints and limits associated with opting into the given DR event.

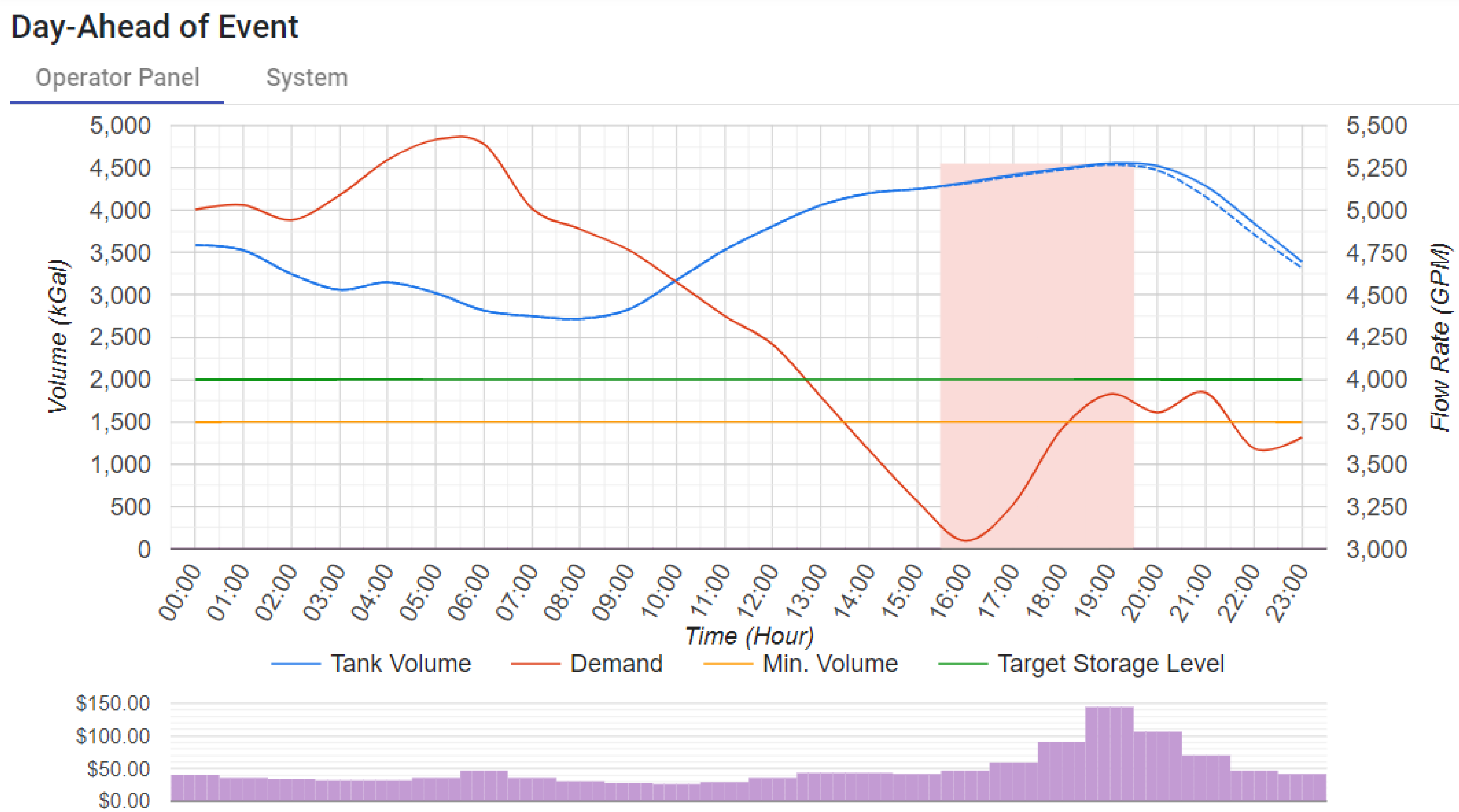
Specifically, the decision support tool was designed to inform operators of DR events and to visualize different opt-in scenarios to assess the feasibility of participation. The tool relies on forecasts of demand and forecasts of pump operation. Because demand is not metered directly, it was obtained indirectly by considering the rate of change of volume of stored water in the Zone D tanks, and the total net pumped flow into the pipeline from all the pumps and interzonal transfers. The demand is the difference between the total pumped flow in the pipeline and the rate of increase of stored water volume. The project team interviewed operators from Cal Water to understand operational constraints in daily water system management, and modeled the constraints to graphically illustrate the extent that constraints may be violated under different pumping strategies. For example, reducing pump speed during DR events could impact the satisfaction of the constraints. Chapter 3 provides further details on the decision support tool design and its field test.

Day-Ahead and Day-of Screens

The decision support tool designed is comprised of two screens that operators use for decision making:

- Figure E-1 shows the day-ahead screen. It is viewed the day before the DR event to assist supervisors in making a provisional opt-in decision.
- Figure E-2 shows the day-of screen. It is viewed on the day of the DR event to allow operators to confirm participation in the DR event, given that conditions may arise that make opting out necessary.

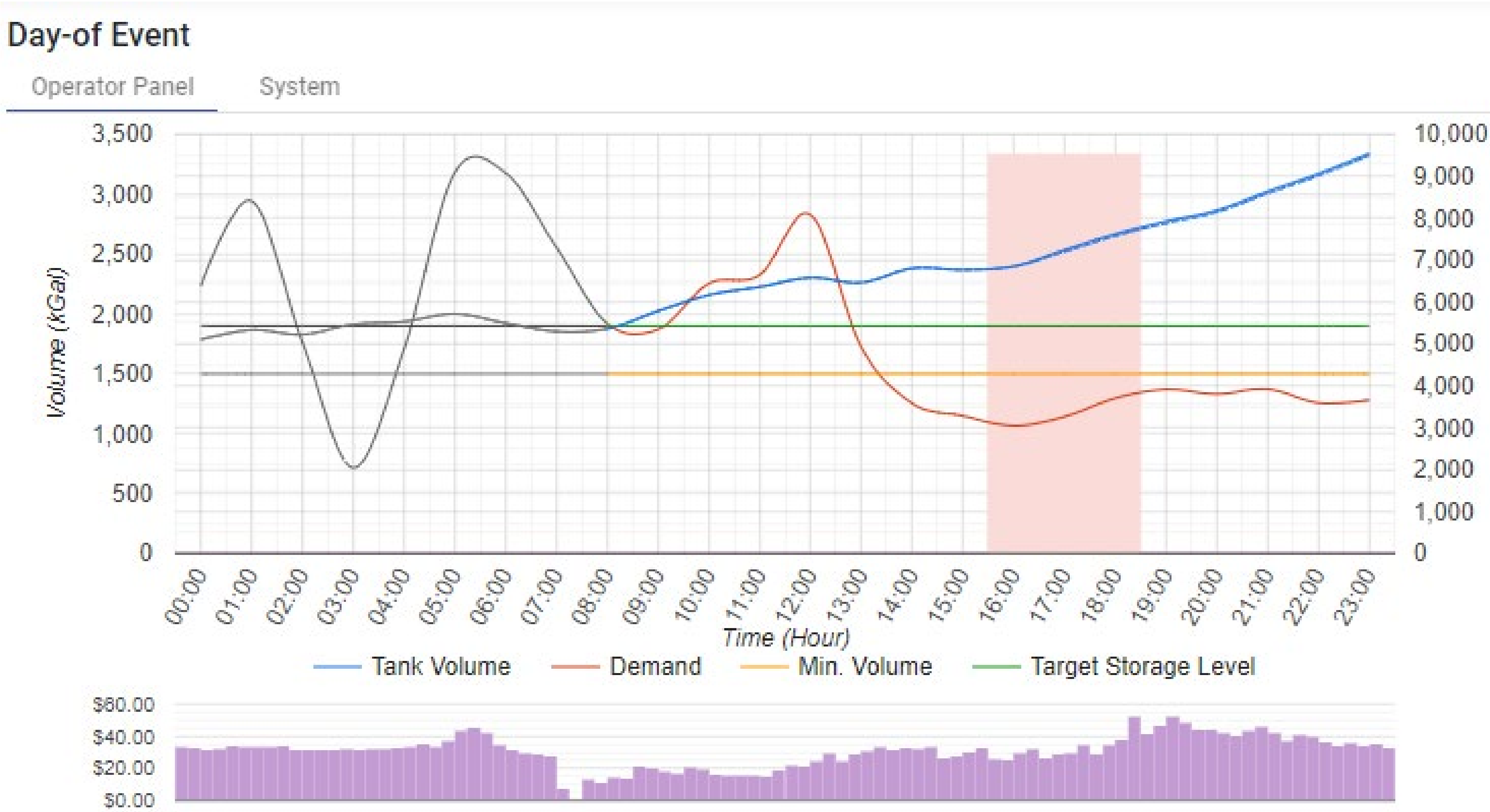
Figure E-1: The Day-Ahead Screen of the Decision Support Tool



The day-ahead decision support tool displays a graphical representation of forecasted tank volume, demand, minimum volume, and target storage level as they change through the day.

Source: EPRI

Figure E-2: Day-of Screen of the Decision Support Tool



In the day-of graphical representation, unlike the day-ahead, hours before 8:00 a.m. have already passed and their profiles are colored in gray.

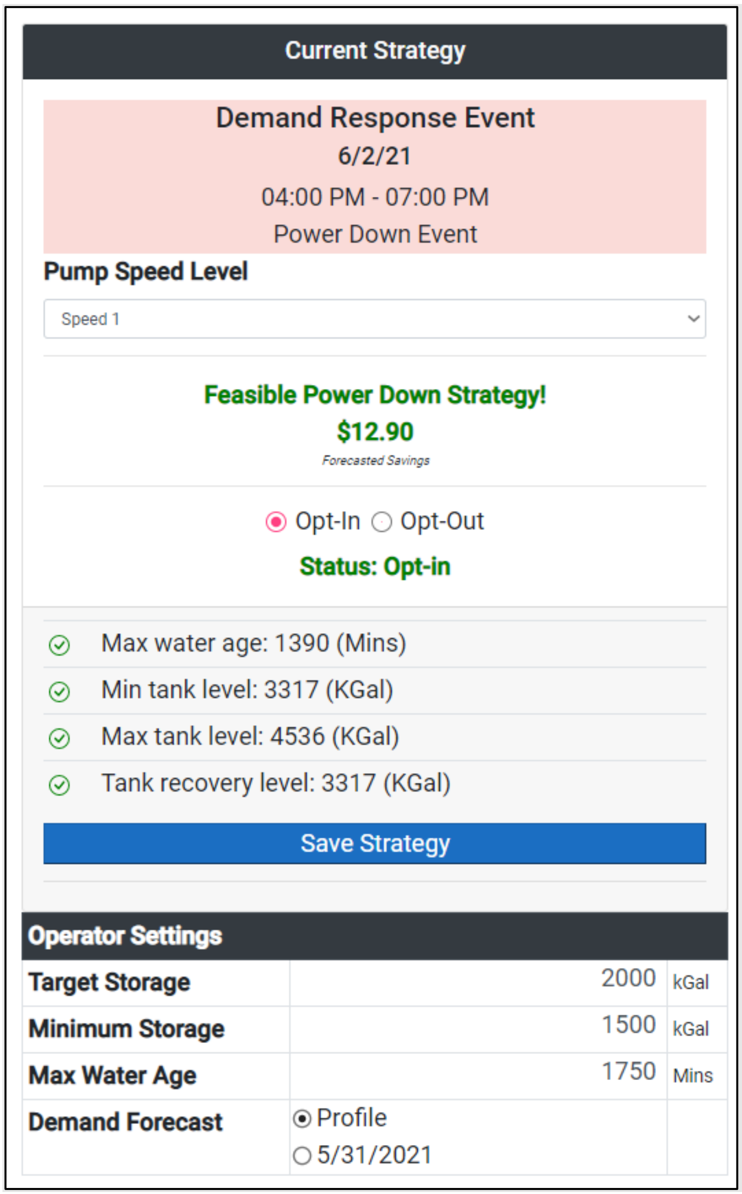
Source: EPRI

The Three Primary Components of Each Screen

Each screen consists of three primary components:

- Figure E-2 shows the **graphical system status** window, which is a visual representation of the forecasted progression, through the day of the DR event, of tank volume, demand, minimum volume, and target storage **level** for zone D.
- Figure E-3 shows the **decision and constraint input window**, which is the decision and constraint portion of the screen.
- Figure E-4 is the **data table** window, which is a tabular representation of data including key system state parameters, including flow rates and tank levels. Some of these tabular parameters are default values that the user can adjust.

Figure E-3: Decision and Constraint Portion of Decision Support Tool



The second component of the day-ahead decision support tool screen is the decision and constraint portion.

Source: EPRI

Figure E-4: Day-Ahead Data Table

Time (HR)	Pump Flow Rate (GPM)	Aggregate Supply (GPM)	Zone Transfer (GPM)	Demand (GPM)	Tank Volume (Strategy) (kGal)	Tank Volume (kGal)	Tank Flow Rate (GPM)	Water Age (mins)
00:00	1,442	3,731	-1,168	5,004	3,587	3,587	-999	500
01:00	1,465	3,782	-4,906	5,031	3,527	3,527	-4,691	560
02:00	1,430	3,678	-3,264	4,942	3,246	3,246	-3,097	620
03:00	1,427	3,669	1,458	5,088	3,060	3,060	1,467	680
04:00	1,459	3,832	-2,111	5,298	3,148	3,148	-2,118	721
05:00	1,495	3,810	-3,331	5,417	3,021	3,021	-3,443	781
06:00	1,486	3,743	-941	5,390	2,814	2,814	-1,102	841
07:00	1,479	3,714	-683	5,010	2,748	2,748	-500	901
08:00	1,468	3,694	1,516	4,888	2,718	2,718	1,791	961
09:00	1,462	3,668	5,420	4,766	2,826	2,826	5,784	984
10:00	1,798	4,029	4,698	4,576	3,173	3,173	5,950	937
11:00	1,859	4,157	3,050	4,376	3,530	3,530	4,690	902
12:00	1,848	4,542	1,974	4,207	3,811	3,811	4,157	895
13:00	1,841	4,879	-486	3,899	4,060	4,060	2,335	900
14:00	1,843	5,270	-2,712	3,584	4,201	4,201	818	930
15:00	1,835	5,480	-2,768	3,282	4,250	4,250	1,265	980
16:00	1,680	5,479	-2,690	3,048	4,316	4,325	1,583	1,025
17:00	1,680	5,492	-2,653	3,263	4,401	4,420	1,231	1,065
18:00	1,680	5,476	-2,670	3,705	4,477	4,494	974	1,107
19:00	1,889	5,301	-3,747	3,915	4,536	4,553	-472	1,152
20:00	1,258	5,621	-7,054	3,805	4,470	4,524	-3,979	1,212
21:00	1,029	5,662	-9,065	3,923	4,156	4,286	-6,297	1,272
22:00	1,203	5,596	-9,595	3,593	3,716	3,908	-6,390	1,331
23:00	938	5,497	-3,197	3,659	3,317	3,525	-421	1,391

The third component of the day-ahead decision support tool screen is the day-ahead data table

Source: EPRI

Screen Component: Graphical System Status

The graphical representation on the day-ahead screen shows the tank volume, demand, minimum volume, and target storage level for zone D. The default demand profile is forecasted based on the daily average profile for demand (obtained from historical data between July 20, 2020 and October 12, 2020). The operator also has the ability to switch the forecasted demand profile in the decision and constraint portion of the screen to the previous day's demand profile if they believe it will be more accurate than the average profile.

The tank volume is a calculated value based on demand and other flows in the system: the dotted line represents tank volume under the selected pump speed and current operation strategy, while the solid line shows tank volume if operated at full speed. The minimum (tank) volume and target storage level are based on constraints input by the operators using the decision and constraint portion of the screen. Volume for the tanks is measured in kgal on the left y-axis, and gallons per minute (GPM) for the demand is measured on the right y-axis. Time of day is displayed on the x-axis data in Pacific Time (Standard or Daylight Saving, as appropriate). A bar plot beneath the graphic shows California ISO's locational marginal hourly electricity prices for the regional pricing node closest to Cal Water (TH_SP15_GEN-APND) in dollars per megawatt.

Screen Component: Decision and Constraint

The decision and constraint portion of the day-ahead screen enables the operator to change the pump speed to off, medium speed or speed 1 (53 Hz / 190 kW), or full speed (60 Hz / 290 kW). Due to operational difficulties associated with turning the pump fully off, the operators chose to reduce the pump speed to speed 1 for all DR events. The given constraints of the system (i.e., maximum water age, minimum tank level, maximum tank level, and tank recovery level) are then updated according to the selected pump speed. If any of the constraints are not met, the operator can adjust the zone's aggregated flows (outside of the DR event period) in the data table to an operation plan that satisfies system constraints, or alternatively change the values of the constraints themselves. Once the constraints are met, the operator can then opt into the DR event for the next day and save the operation strategy. The operator can see the forecasted energy cost impact of the strategy compared to the cost of the default strategy, based on California ISO's locational marginal prices for the regional pricing node "TH_SP15_GEN-APND." "Operator settings" allows the operator to change constraint values and the demand forecast profile to be used.

Screen Component: Data Table

The data table contains eight columns with 24 rows, each representative of an hour of the day. The four leftmost columns contain system flow rates (in GPM) that are populated based on historical data, but can also be edited by the operator. The four remaining columns (shaded in grey) are calculated based on the flow rates and cannot be edited. The operator has the option to edit the system flow rates, in case a better estimate than the default exists, or to test alternative strategies to design an operation plan that satisfies demand and meets constraints on the system.

- The pump flow rate column contains the variable speed pump 6201 in which the power reduction is performed.
- The aggregate supply column is the sum of eight single-speed extraction pumps' flows
- The zone transfer column is the sum of flows in stations 058, 055, 010, 023, and 032.
- The demand column is the expected customer demand. Although this is not controllable, operators may have better estimates than the default based on operational experience (such as demand based on weather, holiday, etc.).
- The tank volume (strategy) column is the combination of station 040 tanks and purchased water from outside the system in the metric of kgal under the selected pump speed and current operation strategy.
- The tank volume column shows the water volume with no interventions from the operator.
- The tank flow rate column is the net flow in or out of the 040 tanks in GPM calculated from the change in mass in tank volume every timestep.
- The water age column is an estimate of the water's age in seconds at the current timestep.

The tool's "day-of" screen has the same components as the day-ahead screen. The difference is that the day-of screen has access to more recent data (for hours that have already passed) and can thus provide a better estimate of the implications of opting in to a DR event. In the graphical representation, this is shown as a grey line up until the hour before the current time, where the current time is 8 a.m. In the data table portion of the screen shown in Figure E-5, the grey background denotes elapsed hours. Hours of the day that have not elapsed are still based on the forecast. The decision and constraint portion of the day-of screen provides the same functionality as the day-ahead, and gives the operator the opportunity to opt-out if warranted by updated conditions.

Figure E-5: Day-of Screen Data Table

Time (HR)	Pump Flow Rate (GPM)	Aggregate Supply (GPM)	Zone Transfer (GPM)	Demand (GPM)	Tank Volume (Strategy) (kGal)	Tank Volume (kGal)	Tank Flow Rate (GPM)	Water Age (mins)
00:00	1,908	6,100	-310	6,382	1,787	1,787	1,316	500
01:00	1,911	6,155	-269	8,405	1,866	1,866	-608	539
02:00	1,891	6,119	-1,576	5,040	1,829	1,829	1,394	598
03:00	1,893	6,158	-5,601	2,049	1,913	1,913	401	631
04:00	1,825	6,143	-2,025	4,874	1,937	1,937	1,070	684
05:00	1,798	6,164	-164	9,084	2,001	2,001	-1,286	722
06:00	1,945	6,133	-160	9,076	1,924	1,924	-1,159	780
07:00	1,933	5,927	-184	7,303	1,854	1,854	374	838
08:00	1,921	6,072	-49	5,488	1,877	1,877	2,455	888
09:00	1,918	4,631	1,020	5,345	2,024	2,024	2,224	884
10:00	1,912	3,662	2,012	6,439	2,158	2,158	1,147	889
11:00	1,899	3,650	2,378	6,649	2,226	2,226	1,277	921
12:00	1,894	3,668	1,835	8,077	2,303	2,303	-679	951
13:00	1,878	3,666	1,366	4,924	2,262	2,262	1,985	1,010
14:00	1,857	2,515	-1,000	3,584	2,381	2,381	-212	1,019
15:00	1,703	3,075	-1,000	3,282	2,369	2,369	496	1,079
16:00	1,680	4,418	-1,000	3,048	2,397	2,398	2,294	1,126
17:00	1,680	4,549	-1,000	3,263	2,520	2,536	2,207	1,131
18:00	1,919	4,539	-1,000	3,705	2,652	2,668	1,753	1,134
19:00	1,921	4,541	-1,000	3,915	2,758	2,774	1,547	1,151
20:00	1,927	5,500	-1,000	3,805	2,851	2,866	2,622	1,174
21:00	1,917	5,500	-1,000	3,923	3,007	3,024	2,494	1,172
22:00	1,895	5,500	-1,000	3,593	3,156	3,173	2,802	1,177
23:00	1,897	5,500	-1,000	3,659	3,324	3,341	2,738	1,178

In the day-of data table, unlike the day-ahead table, hours before 8 a.m. have already passed, and their cells are highlighted gray.

Source: EPRI

Appendix K contains additional detail on the data input options that the decision support tool provides.

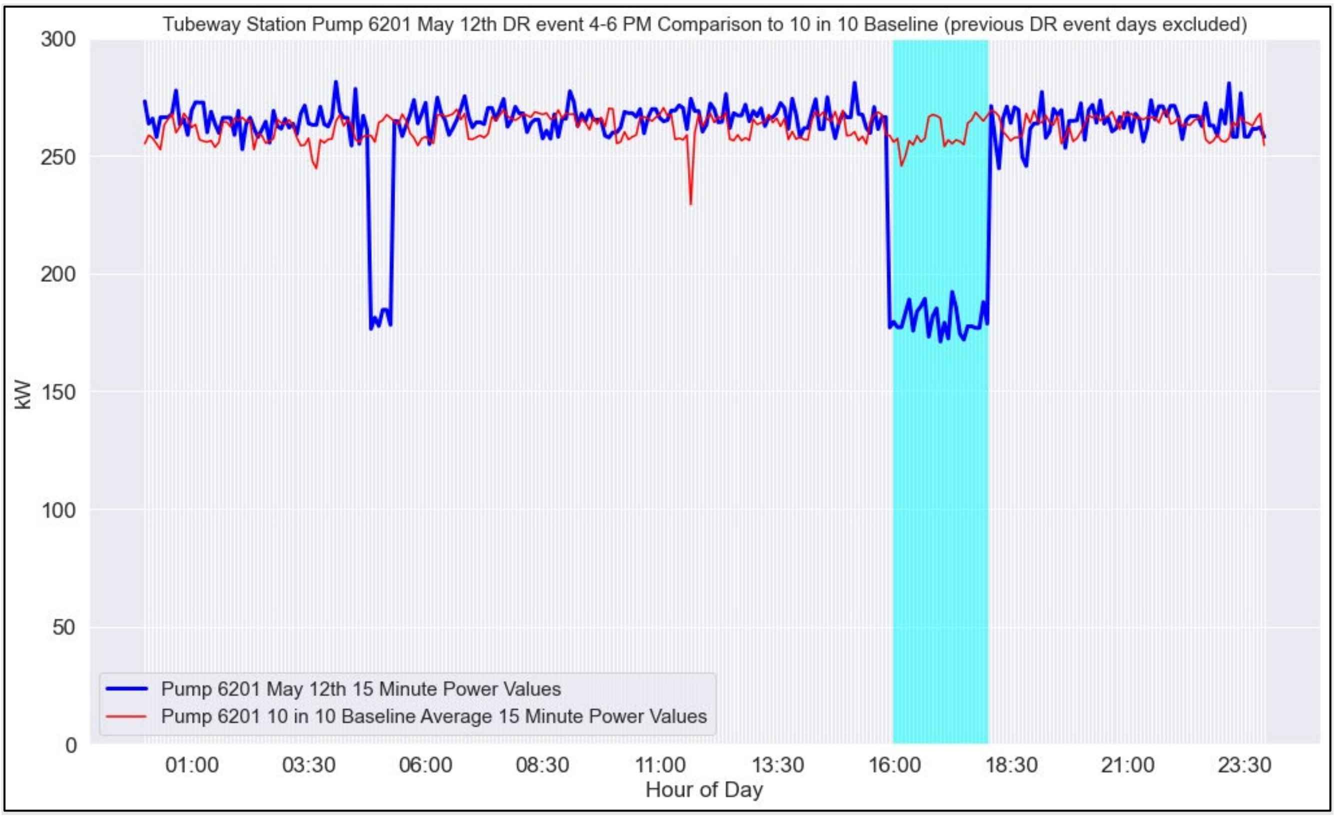
APPENDIX F: Water Pumping Demand Reductions: Results Charts

To illustrate demand reductions achieved, this appendix contains the details of pump performance during each DR event.

May 12, 2021, DR Event

Figure F-1 shows the 79-kW reduction during the May 12, 2021, DR event from 4:00 p.m. to 6:00 p.m. compared to the 10-in-10 baseline.

Figure F-1: Tubeway Station Pump 6201 DR Event on May 12, 2021, from 4:00 to 6:00 p.m. Compared to the 10-in-10 Baseline



The graph shows the 79-kW reduction during the May 12, 2021, DR event from 4:00 p.m.to 6:00 p.m. compared to the 10-in-10 baseline.

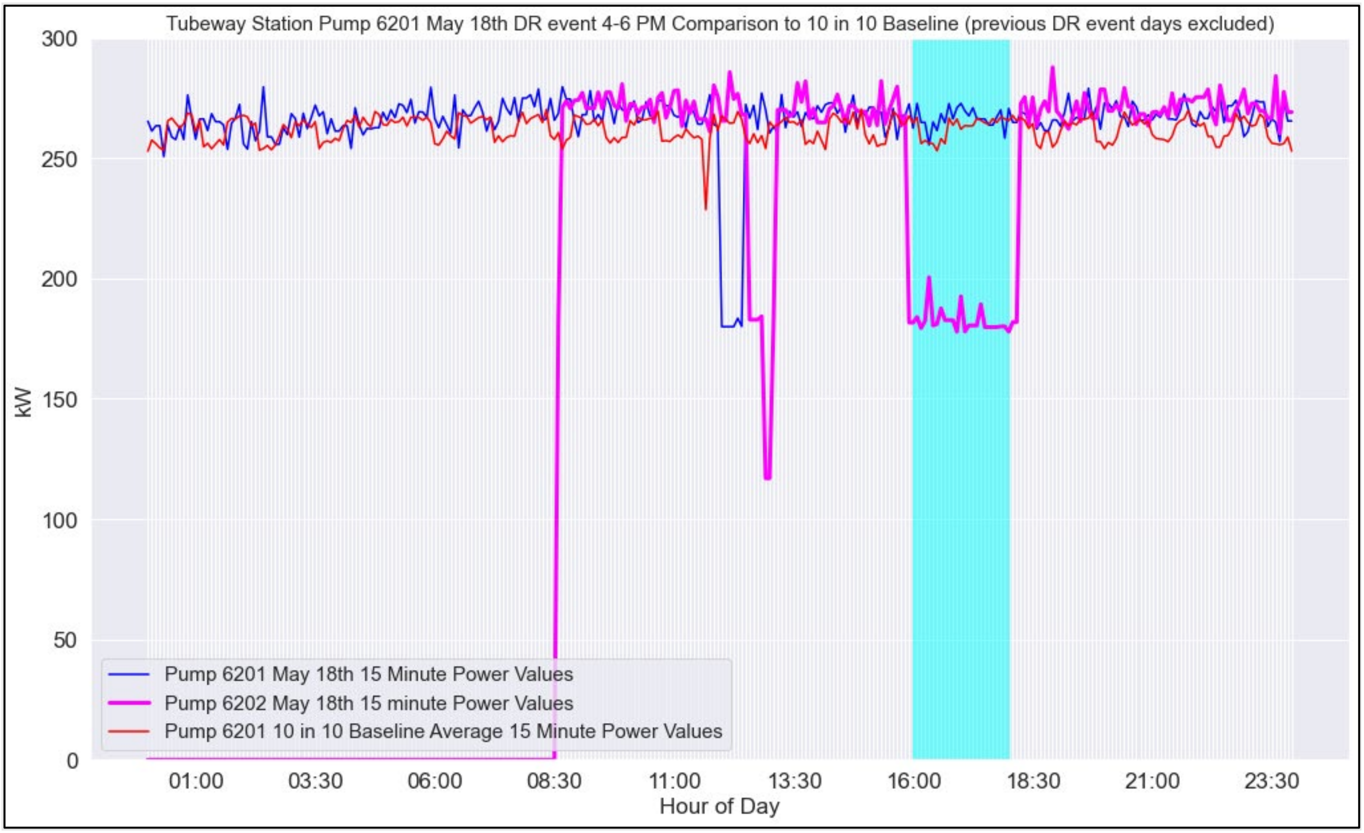
Source: EPRI

May 18, 2021, DR Event

During this DR event, the operator mistakenly reduced power for the 6202 pump rather than the designated test pump number 6201. Although an operator error, the ability to reduce the second variable-speed pump during the DR event points to additional sources of flexibility of the water system. In Figure F-2, pump 6202's response during the DR event is shown alongside pump 6201 and its 10-in-10 baseline.

On May 18, 2021, there was an 80-kW reduction from pump 6202 during the DR event from 4:00 p.m. to 6:00 p.m. compared to the pump 6201 10-in-10 baseline.

Figure F-2: Tubeway Station Pump 6201 DR Event on May 18, 2021, from 4:00 p.m. to 6:00 p.m. Compared to the 10-in-10 Baseline



The graph shows an 80-kW reduction from pump 6202 during the May 18, 2021, DR event from 4:00 p.m. to 6:00 p.m. compared to the pump 6201 10-in-10 baseline

Source: EPRI

May 25, 2021, DR Event

Figure F-3 shows the 84-kW reduction during the DR event of May 25, 2021, from 4:00 p.m. to 6:00 p.m., compared to the 10-in-10 baseline.

Figure F-3. Tubeway Station Pump 6201 DR Event on May 25, 2021, from 4:00 p.m. to 6:00 p.m. Compared to the 10-in-10 Baseline

The graph shows the 84-kW reduction during the May 25, 2021, DR event from 4:00 p.m. to 6:00 p.m. compared to the 10-in-10 baseline.

Source: EPRI

May 27, 2021, DR Event

Figure F-4 shows the 84-kW reduction during the DR event of May 27, 2021, from 4:00 p.m. to 6:00 p.m. compared to the 10-in-10 baseline.

Figure F-4: Tubeway Station Pump 6201 DR Event on May 27, 2021 from 4:00 p.m. to 6:00 p.m. Compared to the 10-in-10 Baseline

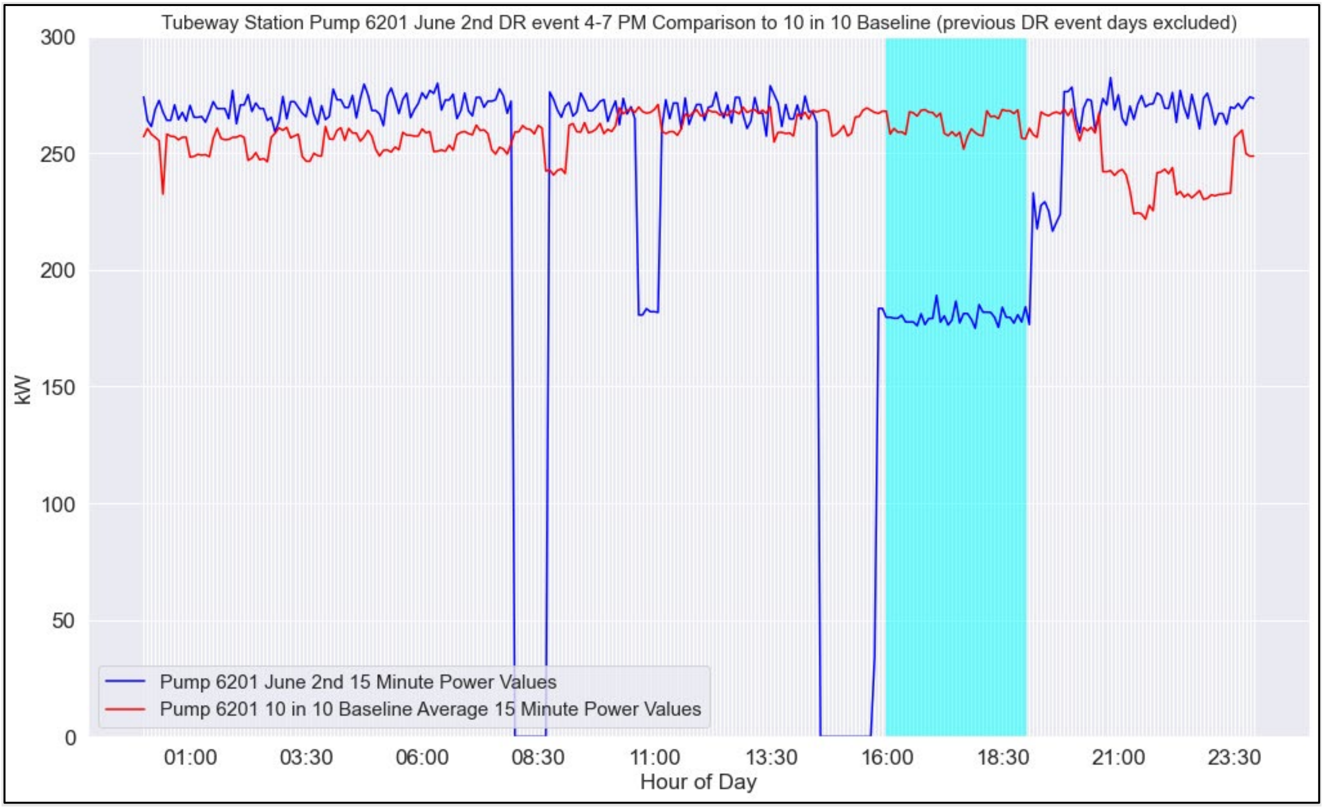
The graph shows the 84-kW reduction during the May 27, 2021, DR event from 4:00 p.m. to 6:00 p.m. compared to the 10-in-10 baseline

Source: EPRI

June 2, 2021, DR Event

Figure F-5 shows the 83-kW reduction during the DR event of June 2, 2021, from 4:00 p.m. to 7:00 p.m. compared to the 10-in-10 baseline.

Figure F-5: Tubeway Station Pump 6201 DR Event on June 2, 2021, from 4:00 p.m. to 7:00 p.m., Compared to the 10-in-10 Baseline



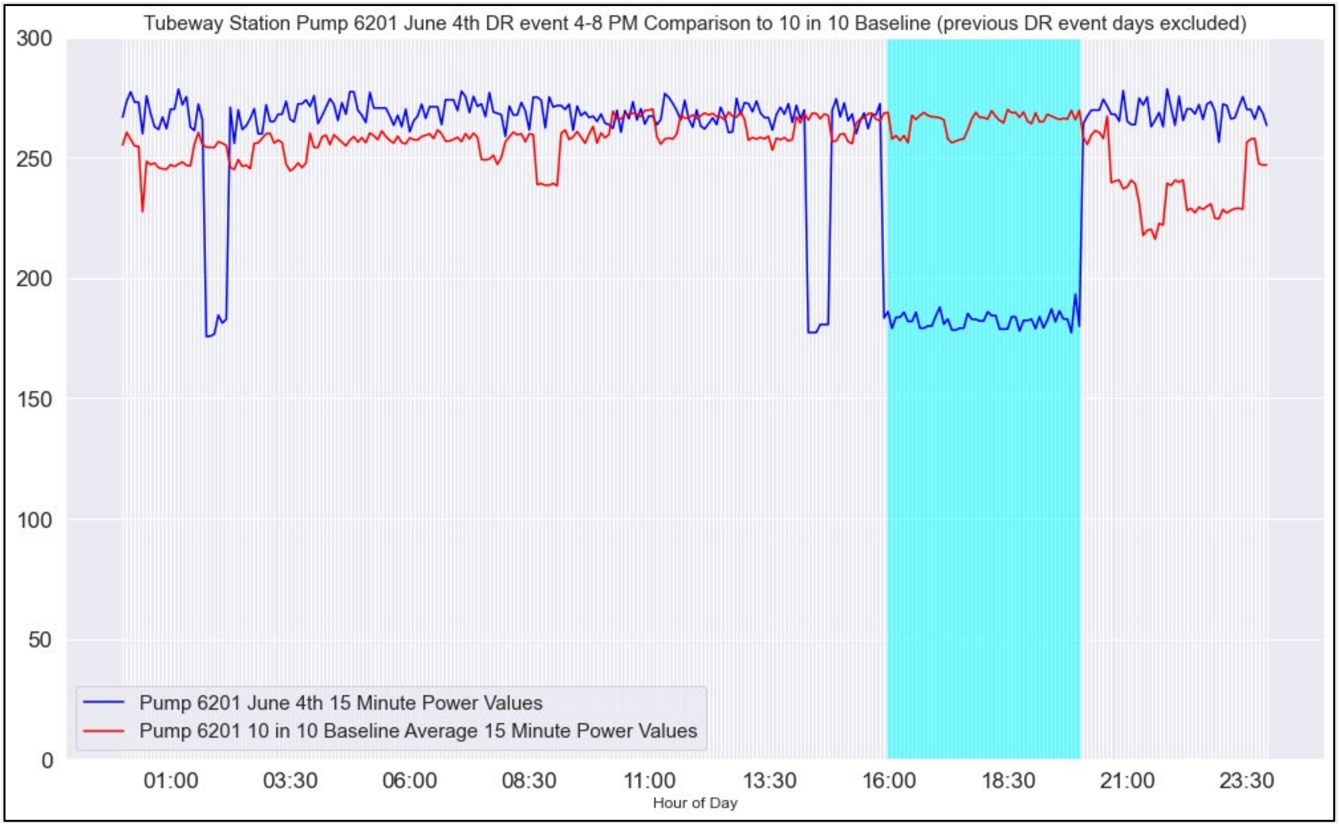
The graph shows the 83-kW reduction during the June 2, 2021, DR event from 4:00 p.m. to 7:00 p.m. compared to the 10-in-10 baseline

Source: EPRI

June 4, 2021, DR Event

Figure F-6 shows the 83-kW reduction during the DR event of June 4, 2021 from 4:00 p.m. to 8:00 p.m. compared to the 10-in-10 baseline.

Figure F-6: Tubeway Station Pump 6201 DR Event on June 4, 2021, from 4:00 p.m. to 8:00 p.m. Compared to the 10-in-10 Baseline



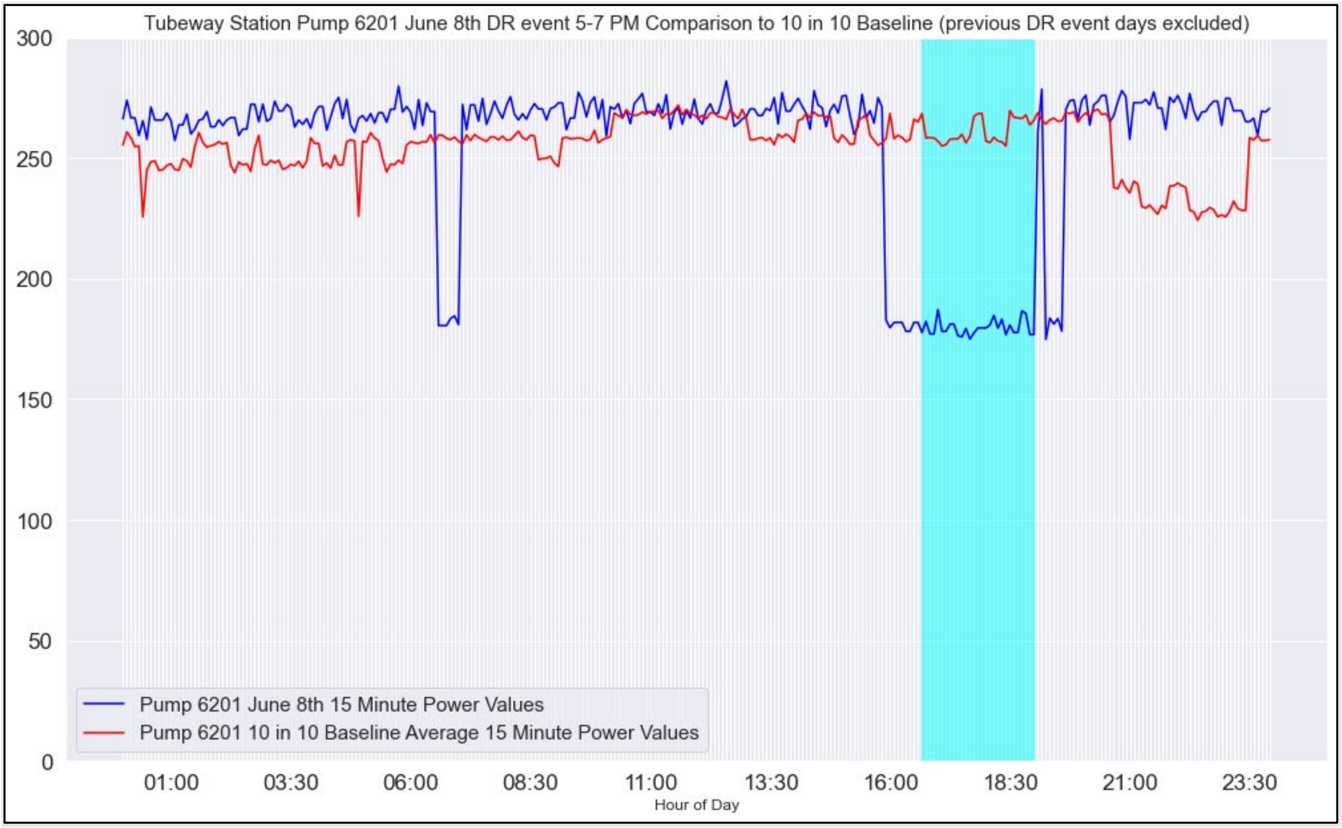
The graph shows the 83-kW reduction during the June 4, 2021, DR event from 4:00 p.m. to 8:00 p.m. compared to the 10-in-10 baseline

Source: EPRI

June 8, 2021 DR Event

Figure F-7 shows the 83-kW reduction during the DR event of June 8, 2021, from 5:00 p.m. to 7:00 p.m. compared to the 10-in-10 baseline.

Figure F-7: Tubeway Station Pump 6201 DR Event of June 8, 2021, from 5:00 p.m. to 7:00 p.m. Compared to the 10-in-10 Baseline



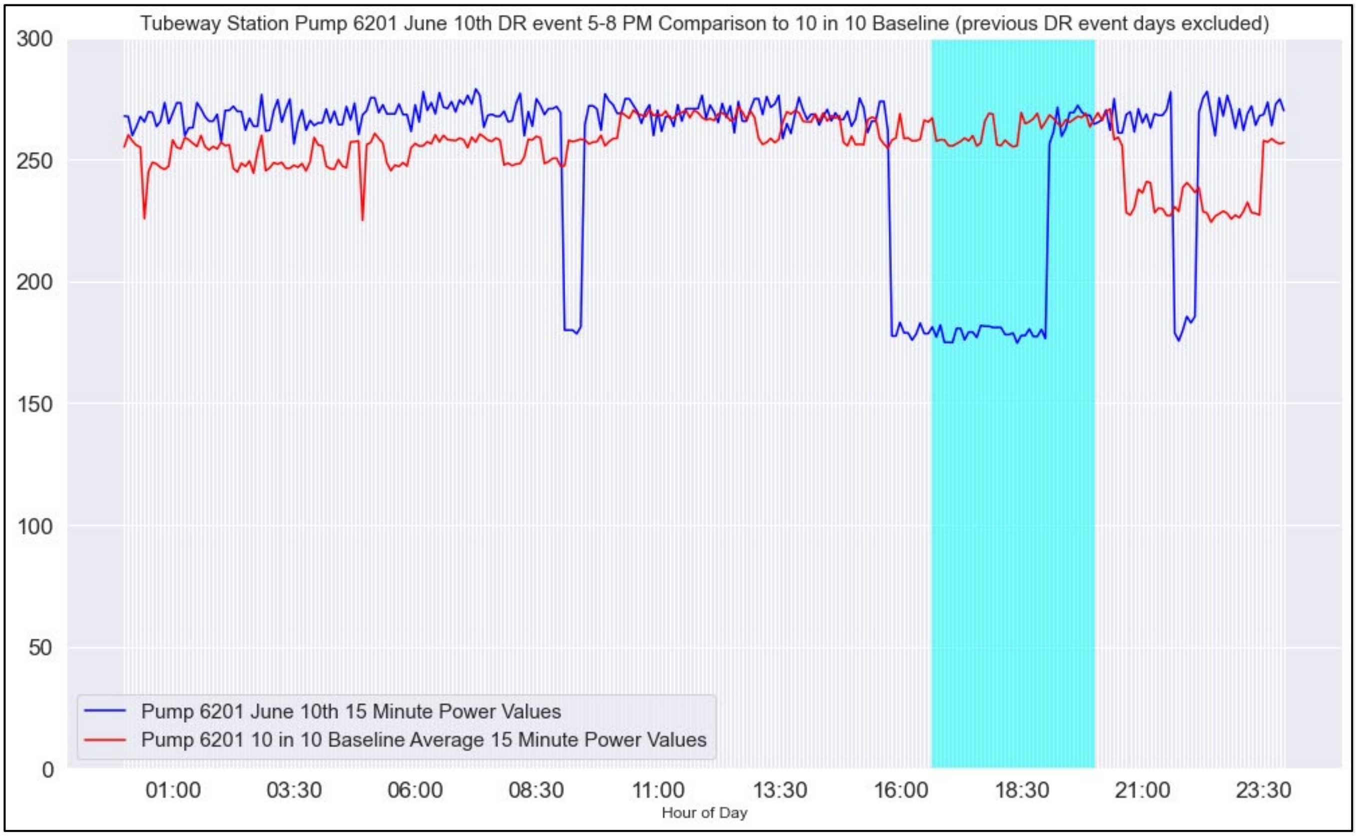
The graph shows the 83-kW reduction during the June 8, 2021, DR event from 5:00 p.m. to 7:00 p.m. compared to the 10-in-10 baseline

Source: EPRI

June 10, 2021, DR Event

Figure F-8 shows the 55-kW reduction during the DR event of June 10, 2021, from 5:00 p.m. to 8:00 p.m. compared to the 10-in-10 baseline.

Figure F-8: Tubeway Station Pump 6201 DR Event of June 10, 2021, from 5:00 p.m. to 8:00 p.m. Compared to the 10-in-10 Baseline



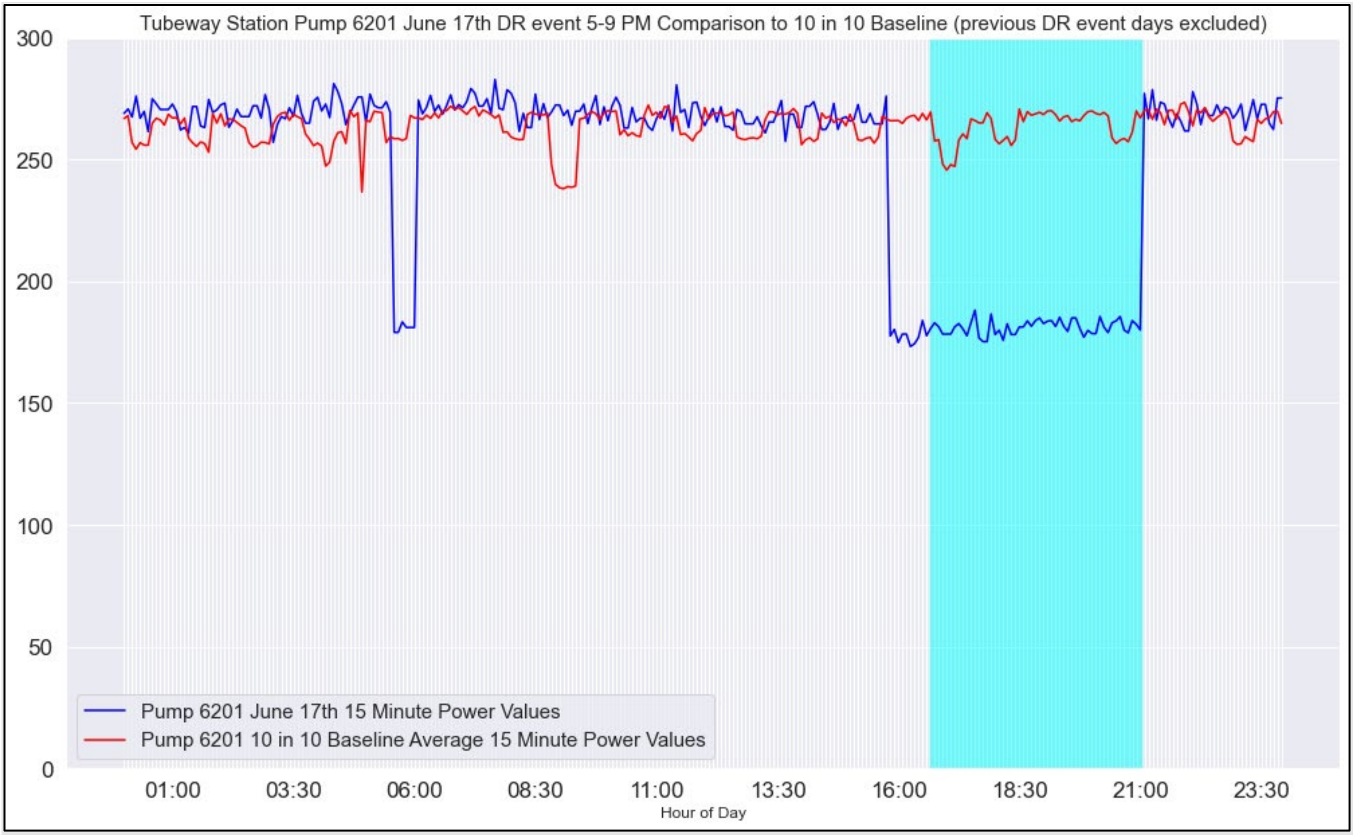
The graph shows the 55-kW reduction during the June 10, 2021, DR event from 5:00 p.m. to 8:00 p.m. compared to the 10-in-10 baseline

Source: EPRI

June 17, 2021, DR Event

Figure F-9 shows the 82-kW reduction during the DR event of June 17, 2021, from 5:00 p.m. to 9:00 p.m. compared to the 10-in-10 baseline. Before this event, the participating site had notified of its plan to reduce demand starting at 4:00 p.m. instead of 5:00 p.m. for ease of execution before an operator shift change.

Figure F-9: Tubeway Station Pump 6201 June 17, 2021, DR Event from 5:00 p.m. to 9:00 p.m. Compared to the 10-in-10 Baseline



The graph shows the 82-kW reduction during the June 17, 2021, DR event from 5:00 p.m. to 9:00 p.m. compared to the 10-in-10 baseline

Source: EPRI

APPENDIX G: Details of Refrigeration Tests Conducted and Results of "Calibration" Testing

This appendix describes the refrigeration site configuration, experimental setup, data validation, baseline development, field test experiments conducted, and results of the "calibration" testing.

Site Configuration

Figure G-1 shows a simplified process diagram of the key components of the ammonia-based refrigeration system at the Lineage site. The four frozen rooms in which the evaporators were controlled for DR purposes are shown (Rooms 3, 7, 8, and 10) with their respective evaporators (labeled "EV-33B," etc.). The two-stage system incorporates low-pressure and high-pressure stages, including recirculators, to boost system efficiency.

Figure G-2 shows the physical layout of the Lineage plant, with circles indicating the four rooms that were controlled for DR.

Figure G-1: Simplified Process Diagram of Lineage Refrigeration System

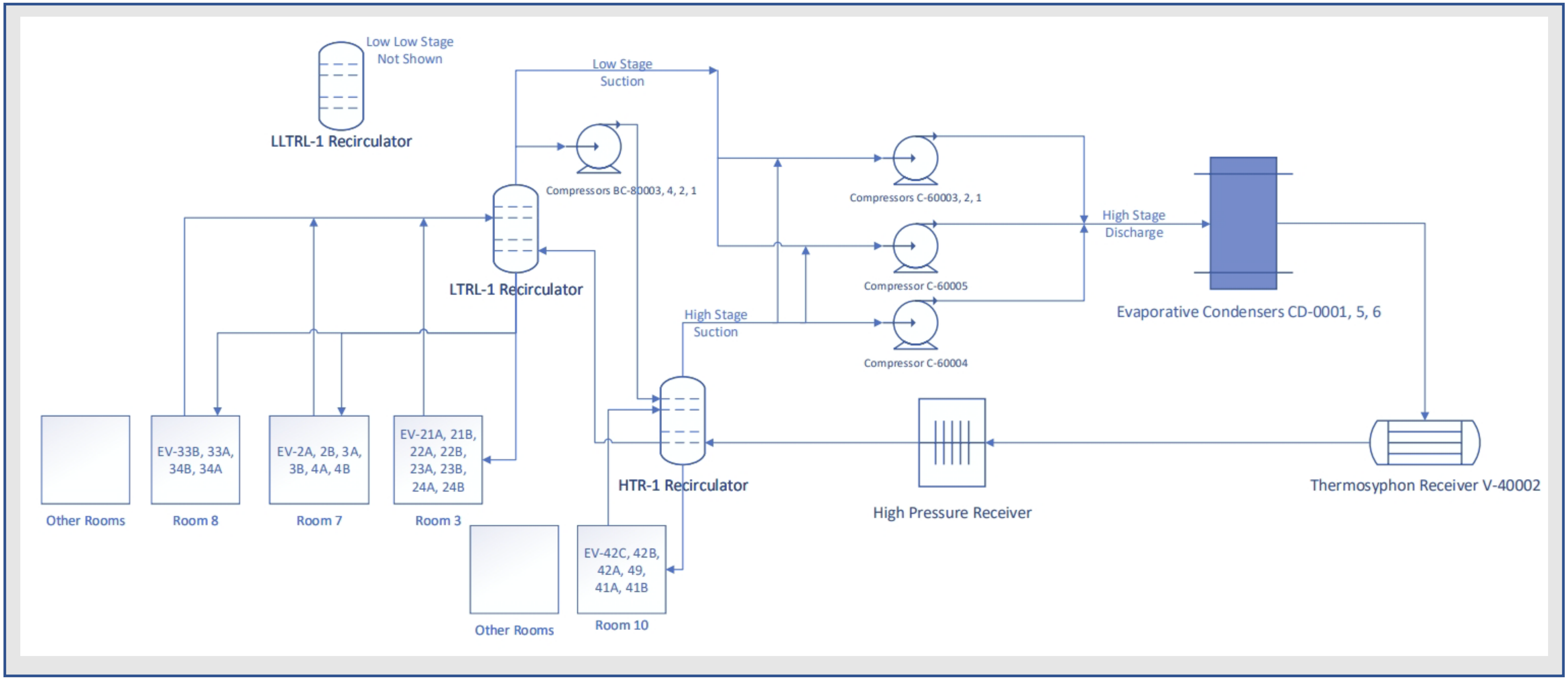
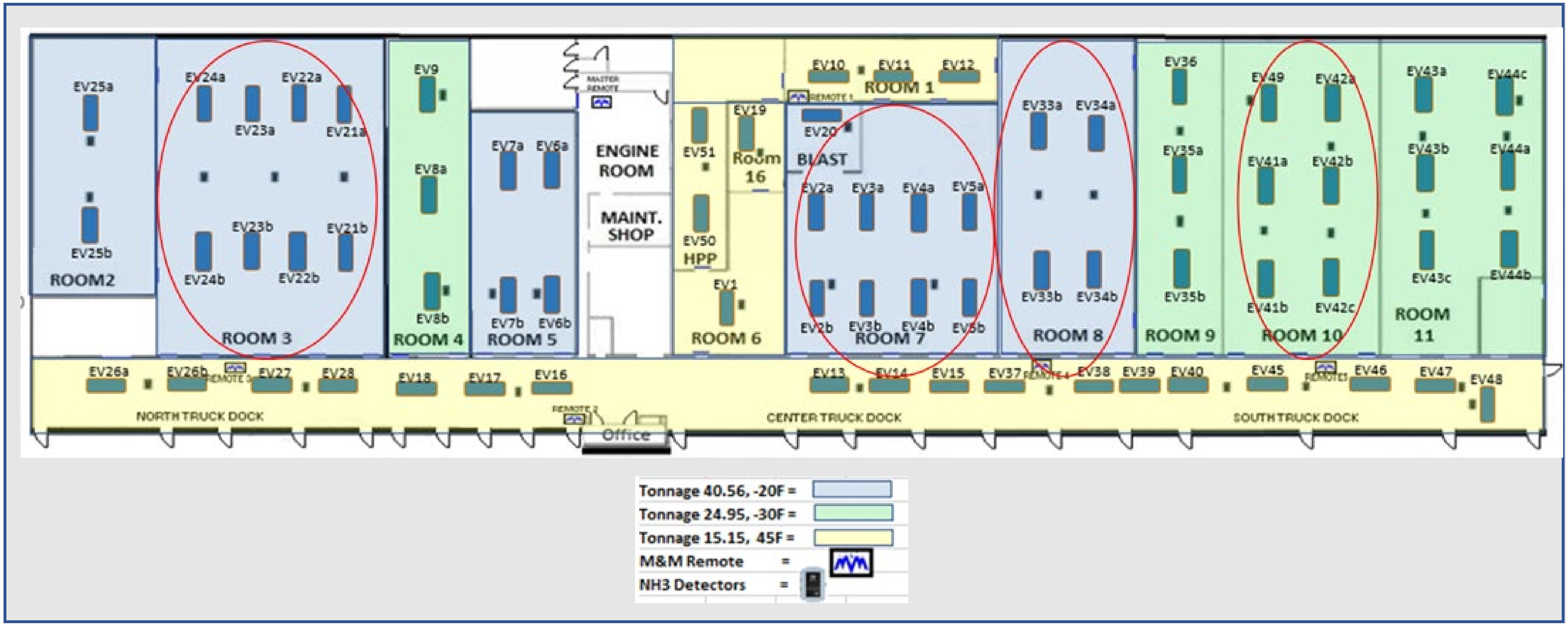


Diagram showing a simplified process of the Lineage site refrigeration system

Source: EPRI

Figure G-2: Physical Layout of the Lineage Refrigeration System



Physical layout of the Lineage refrigeration system. Rooms 3, 7, and 8 participated in DR experiments.

Source: Lineage Logistics

Experimental Setup

Using the measurement and verification (M&V) plan and system architecture setup to send signals, the project started with a series of thermal DR events. This involved testing the thermal power-down control strategy ("power down") and thermal power-up control strategy ("power up"):

- **Thermal power-down control strategy**. To test for grid emergencies in which an additional supply of power is needed, the team pre-cooled the refrigeration plant by reducing frozen room minimum temperature setpoint when notified, until the power-down event occurred. During the power-down event, the team relaxed the setpoint, using its thermal storage capabilities to reduce the needed refrigeration demand during the event period. The pre-cooling is necessary to prevent the food temperature from exceeding its maximum allowable value during the power-down event.
- **Thermal power-up control strategy**. To test for grid emergencies in which there is an oversupply of power, the team over-cooled the refrigeration plant by reducing its minimum temperature setpoint when the power-up event occurred. The team then relaxed the minimum temperature setpoint when the event ended to recover the excess energy stored in the system.

Data Validation

The team used various data sources for analysis during these experiments, including the following:

- Entire site power meter data from SCE.
- Entire site power meter data from the on-site M&M[15] monitoring system.
- Individual compressor data from the on-site M&M monitoring system.
- Individual compressor data received from the EPRI VTN.

The data was verified and validated from all sources. Figure G-3 shows that the power data received from SCE and from the site M&M monitoring system were identical. The compressor power data received from the VTN also matched the (M&M) site monitoring system.

[15] M&M Systems is the control system company that serves the Lineage Plant at Mira Loma.

Figure G-3. Comparison of Power Data Sources

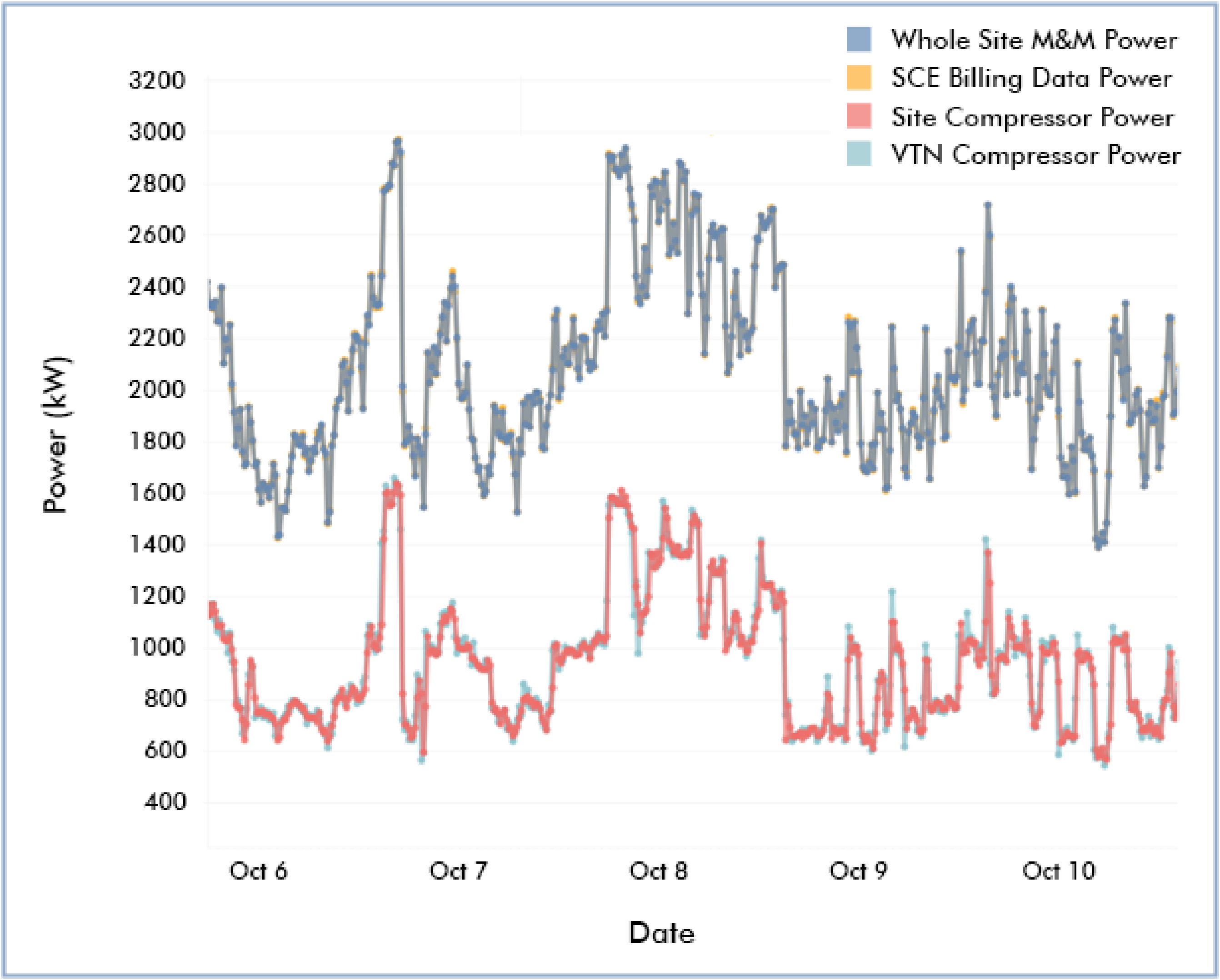


Diagram showing the comparison of various data sources for power metering

Source: EPRI

Experiments Conducted

The project team designed a calibration plan, shown in Table G-1, that is consistent with utility needs for advanced DR and aligned with recent developments in power markets and power generation in California. The signals sent included requested capacity, DR scheduled start time, and duration. The team varied the requested capacity between 15 percent-30 percent, and the control system attempted to achieve this by varying the number of rooms controlled:

- **Level 1** is a 30 percent increase/decrease from the operating setpoint for 1 hour, with a 1-hour notification period. (All four rooms are controlled.)
- **Level 2** is a 20 percent increase/decrease from the operating setpoint for five hours, with a 12-hour notification period. (Three rooms are controlled.)
- **Level 3** is a 15 percent increase/decrease from the operating setpoint for eight hours, with a 24-hour notification period. (Two rooms are controlled.)

Table G-1: Experimental Plan for Refrigerated Plant DR at Lineage Site

Event #	Date	Requested Capacity	DR Scheduled Start Time (PT)	DR Scheduled Start Time (UTC)*	Duration (Hours)	Advance Notice (Hours)
TEST	September 9, 2020	30% - Initial Test	5:00 p.m.	12:00 a.m.	24	24
1	October 6, 2020	20% - Power Down	5:00 p.m.	12:00 a.m.	5	12
2	October 8, 2020	15%- Power Down	3:00 p.m.	10:00 p.m.	8	24
3	October 9, 2020	30% - Power Up	2:30 p.m.	9:30 p.m.	1	1
4	October 12, 2020	30% - Power Up	2:30 p.m.	9:30 p.m.	1	2
5	October 15, 2020	15% - Power Up	4:30 p.m.	11:30 p.m.	8	16
6	October 20, 2020	30% - Power Down	12:45 p.m.	7:45 p.m.	1	1
7	October 23, 2020	30% - Power Down	2:00 p.m.	9:00 p.m.	1	1
8	October 29, 2020	15% - Power Down	3:00 p.m.	10:00 p.m.	8	24
9	November 2, 2020	30% - Power Up	3:00 p.m.	11:00 p.m.	1	1
10	November 3, 2020	20% - Power Down	2:00 p.m.	10:00 p.m.	5	12
11	November 6, 2020	15% - Power Up	11:00 a.m.	7:00 p.m.	8	24
12	November 9, 2020	20% - Power Up	11:30 a.m.	6:30 p.m.	5	7
13	November 16, 2020	30% - Power Down	3:15 p.m.	10:15 p.m.	1	1
14	November 17, 2020	20% - Power Down	1:00 p.m.	8:00 p.m.	5	12
15	December 11, 2020	15% - Power Up	11:00 a.m.	6:00 p.m.	8	24
16	December 15, 2020	30% - Power Up	2:30 p.m.	9:30 p.m.	1	1
17	December 17, 2020	20% - Power Up	1:00 p.m.	8:00 p.m.	5	12

*UTC = coordinated universal time

Source: EPRI

Baseline Development

To compare the DR results to normal operations, a reliable baseline of operation for the controlled compressors was needed. Based on an analysis of data during the study period, the team found high day-to-day variability due the plant's operations. Due to this irregular behavior, a representative baseline under conditions similar to the test conditions was needed. To ensure accurate results, the team investigated two techniques for developing a baseline:

- Averaging the compressors' most recent 24 hours of power demand before the change in setpoint due to the DR event
- Developing a temperature-adjusted ("normalized") load shape using the entirety of data acquired during the study period.

The two methods yielded similar results, with an average 5 percent difference. Based on further analysis and for simplicity, the team selected the 24-hour ahead approach.

Equations Used in the Analysis

The team used the following equations to calculate the results:

Pre-Cool % Difference. This is the difference in average power before a DR power-down event for the duration of pre-precooling, compared to the baseline for the same period of the day. During a DR power-up event, this is the comparison of average power for the duration of the event period. This number is expected to be positive in general.

$$\frac{\text{Average Power}_{\text{PreCool}} - \text{Average Power}_{\text{Baseline}}}{\text{Average Power}_{\text{Baseline}}} \text{ x } 100\%$$

Power-Down % Difference. This is the difference in average power for the duration of the DR power-down event, compared to the baseline over the same period of day. During a DR power-up event, this is the average power during the rebound period.

$$\frac{\text{Average Power}_{\text{DR Event}} - \text{Average Power}_{\text{Baseline}}}{\text{Average Power}_{\text{Baseline}}} \text{ x } 100\%$$

Extra Pre-Cool Energy. This is the extra energy used for pre-cooling during a DR power-down event, compared to the baseline. It can also be the extra energy used during the DR power-up event.

$$(\text{Average Power}_{\text{PreCool}} - \text{Average Power}_{\text{Baseline}}) \text{ x Duration}_{\text{PreCool}}$$

Energy Reduction During Event. This is the amount of energy saved from the DR power-down event, compared to the baseline. It is also the amount of energy reduced during the rebound period in a DR power-up event.

$$(\text{Average Power}_{\text{DR Event}} - \text{Average Power}_{\text{Baseline}}) \text{ x Duration}_{\text{DR Event}}$$

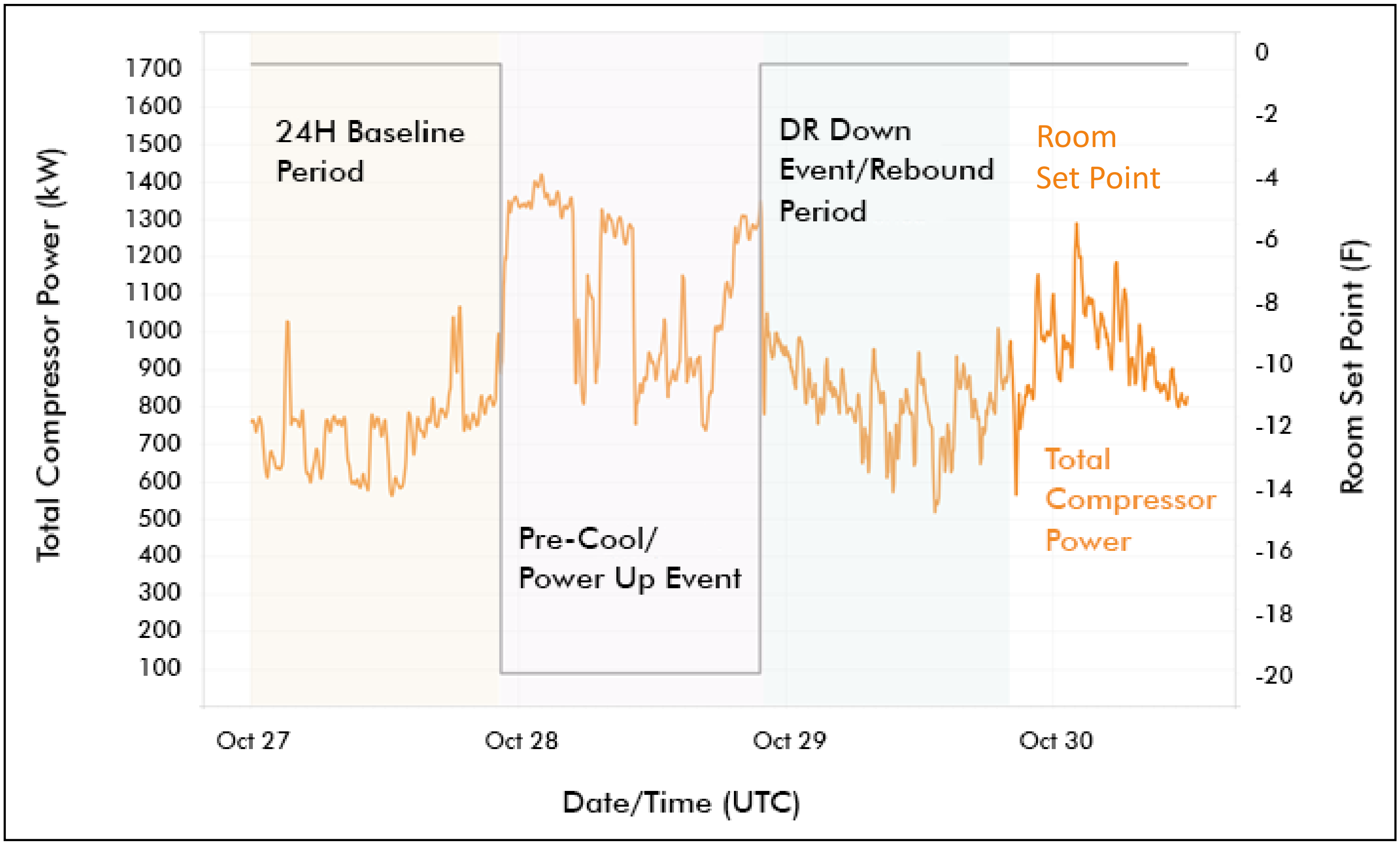
Energy Penalty. This is the excess energy used over the course of a DR event, compared to the baseline.

$$\text{Extra PreCool Energy} + \text{Energy Reduction}$$

Due to the irregular daily behavior of the refrigeration plants, a recent baseline was needed to minimize the amount of variability due to time. The first baseline method considered the average of the compressors' most recent 24 hours of power usage before the change in setpoint by the DR event. For power-down events, this was the 24 hours before the pre-cool period. For the power-up events, this was the 24 hours before the event. The baselines would vary per event day and ranged from 661-950 kW, depending on the day. In cases where events were scheduled close together, the most recent undisturbed 12-24 hour period was averaged. For analyses, the average power during the baseline was compared to the average power during the DR events.

Figure G-4 shows an example of the analysis timeframes with real data (the first method listed above). The baseline period is defined as 24 hours before the change in setpoint for pre-cooling/power up. The pre-cool/power-up event period is when the set-point is lowered below normal operating conditions. The DR down/rebound period is the timeframe after the pre-cool period when the set-point is raised to normal operating conditions.

Figure G-4: Example DR Event Analysis



An example analysis of a DR event during experimentation

Source: EPRI

The second method that was analyzed included a temperature-adjusted load shape using the data acquired between October 15, 2020, and December 31, 2020. This accounted for variability in outdoor temperature that may impact the compressor load during operations. Data when DR events occurred were removed from the baseline development before processing. Figure G-5 shows the compressor daily load shapes, and the thick line in the middle is the average of the dataset. The data shows a high amount of daily variability due to the operations of the refrigeration plant. Incoming and outgoing food product can cause additional demand strain on the compressor systems, leading to spikes in power demand.

Figure G-5: Daily Load Profiles of the Total Compressor Power

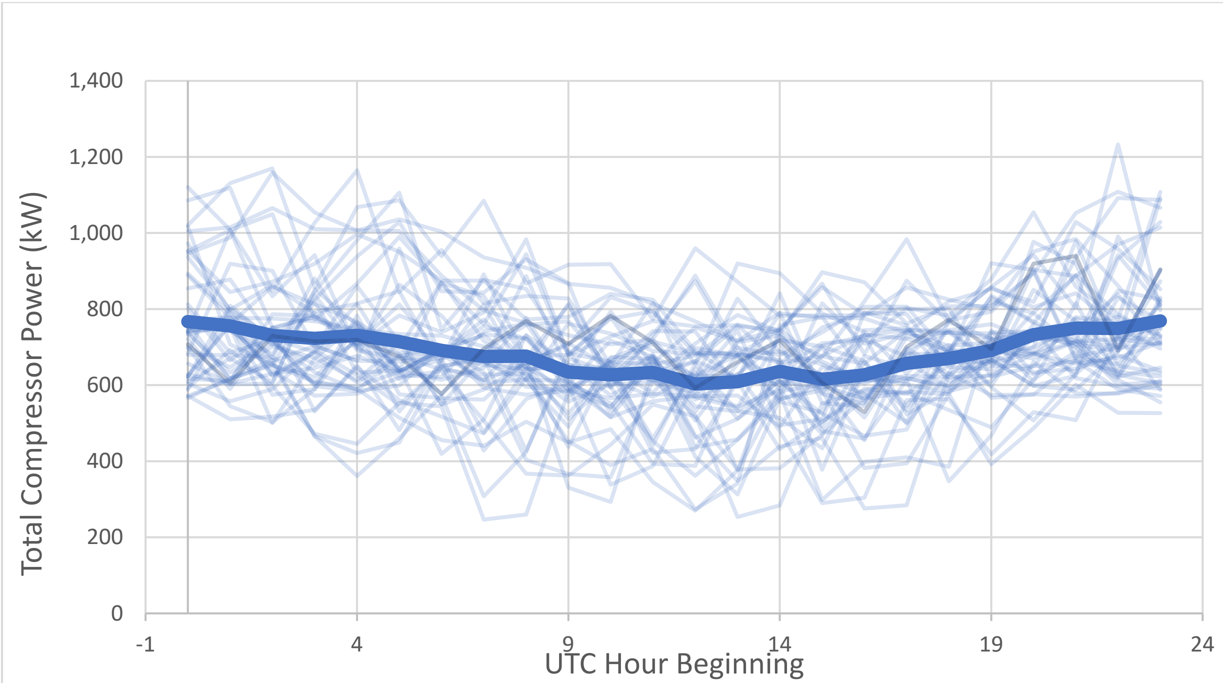


Diagram showing the daily total compressor load profiles from October 15, 2020, to December 31, 2020

Source: EPRI

From the dataset, the normalized load shape shown in Figure G-6 was developed. Figure G-7 shows how this load shape was then adjusted to a temperature regression model developed using the maximum daily temperature.

Figure G-6: Normalized Compressor Load Shape

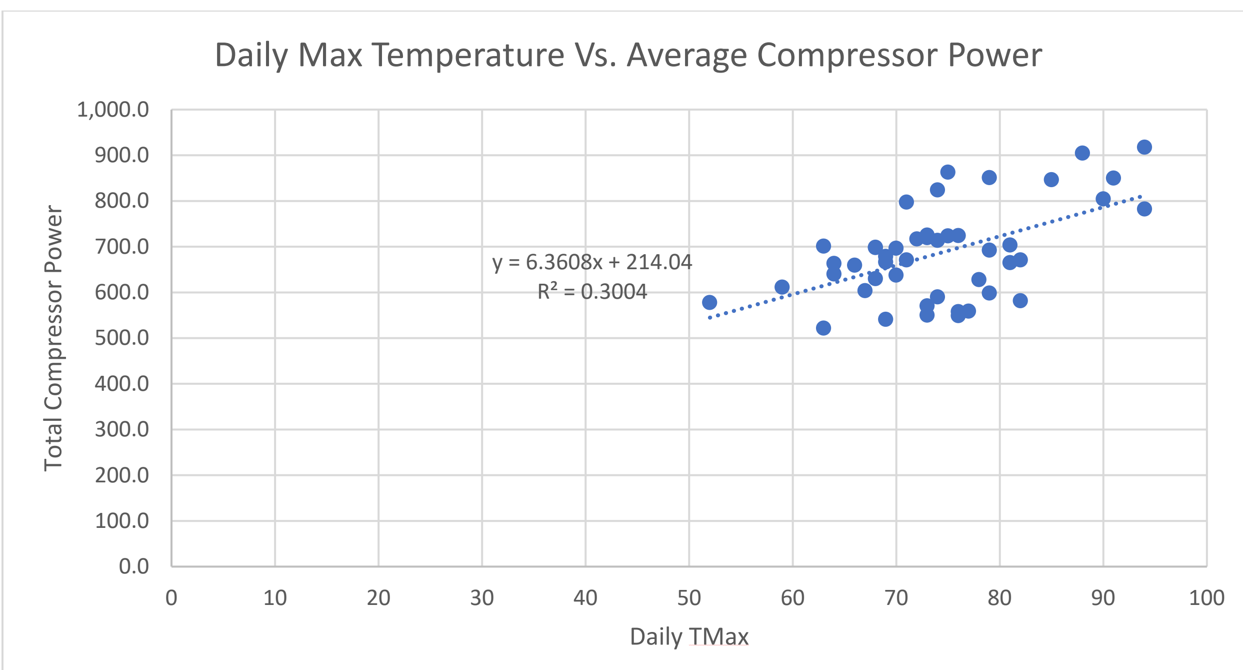
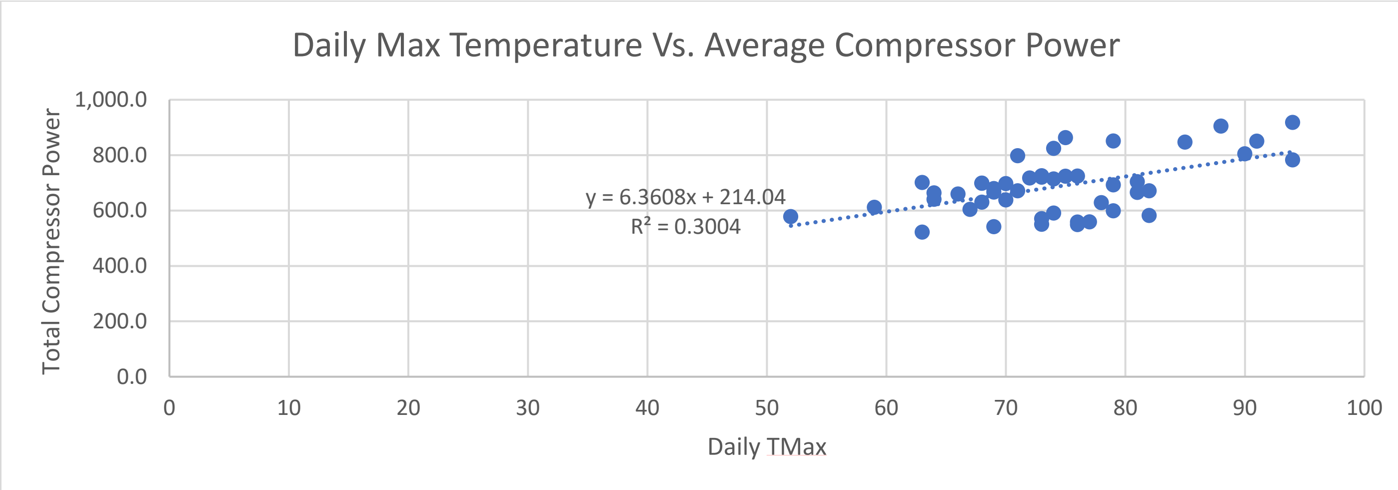


Diagram showing a normalized load shape of the total compressor demand

Source: EPRI

Figure G-7: Regression for Daily Maximum Temperature and Average Compressor Power



Regression for the daily maximum temperature and average compressor power show a slight correlation.

Source: EPRI

Table G-2 summarizes the difference between the baselines for the dataset between October 15, 2020, and December 31, 2020. Overall, the performance between the two baselines was similar, with only an average 5 percent (34 kW) higher baseline using the model approach. The standard deviation of the modeled baseline was 81, whereas the standard deviation of the 24 hour-ahead approach was 73. With the similarity in average performance, lower standard deviation, and greater data availability, the 24 hour-ahead approach was chosen for the comprehensive analyses.

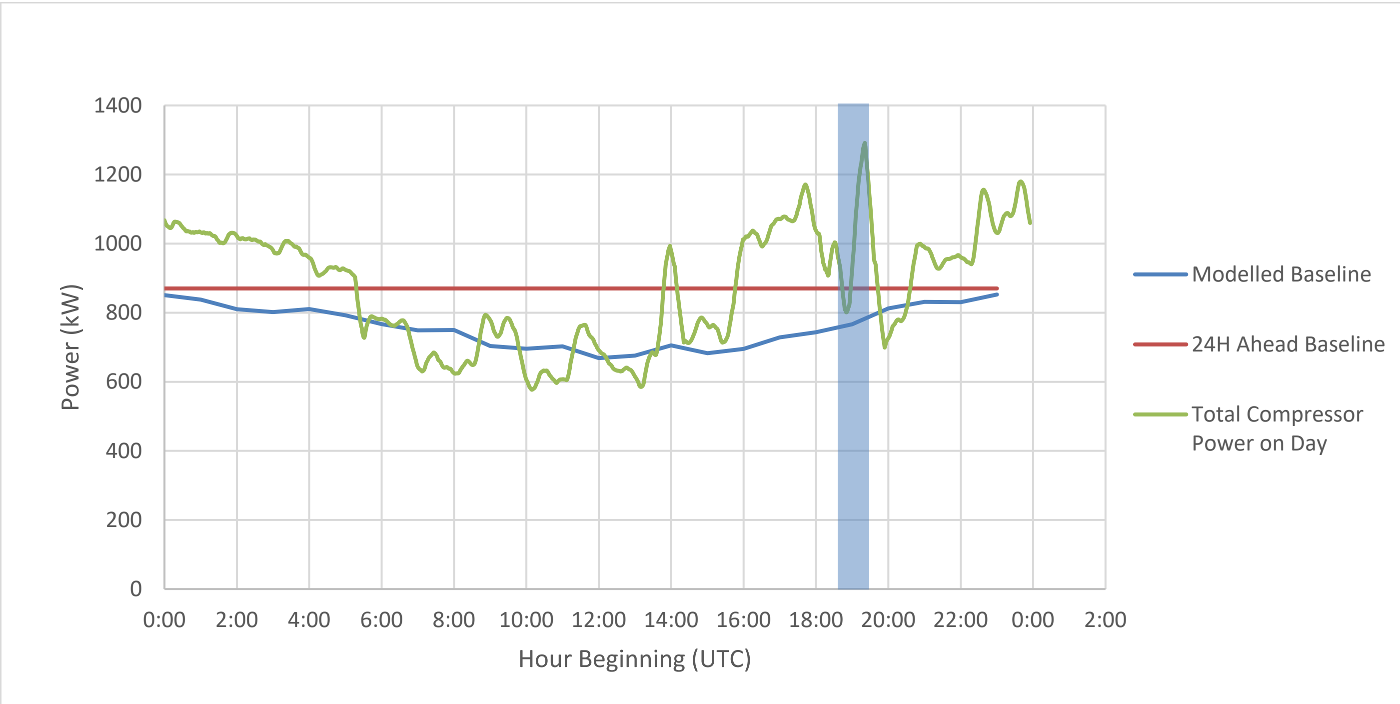
Table G-2: Summary of Baseline Differences

Event #	Compressor Modeled Baseline (kW)	Compressor 24-hour Baseline (kW)	Baseline Difference (kW) (Modeled 24-hour Baseline)	Percent Difference
6	812	870	-58	-7%
7	762	865	-103	-12%
8	837	736	101	14%
9	860	745	115	15%
10	857	745	112	15%
11	730	811	-81	-10%
12	648	661	-13	-2%
13	879	672	207	31%
14	795	672	123	18%
15	635	696	-61	-9%
16	713	661	52	8%
17	691	681	10	1%
Average	768	735	34	5%

Source: EPRI

Figure G-8 compares the baselines for October 20, 2020. For all baseline comparisons, only the average power during the specific event time was compared.

Figure G-8: Example Comparison of Baselines for A Single-Event Day (October 20, 2020)



The baselines developed for a single-event day show similarities in results.

Source: EPRI

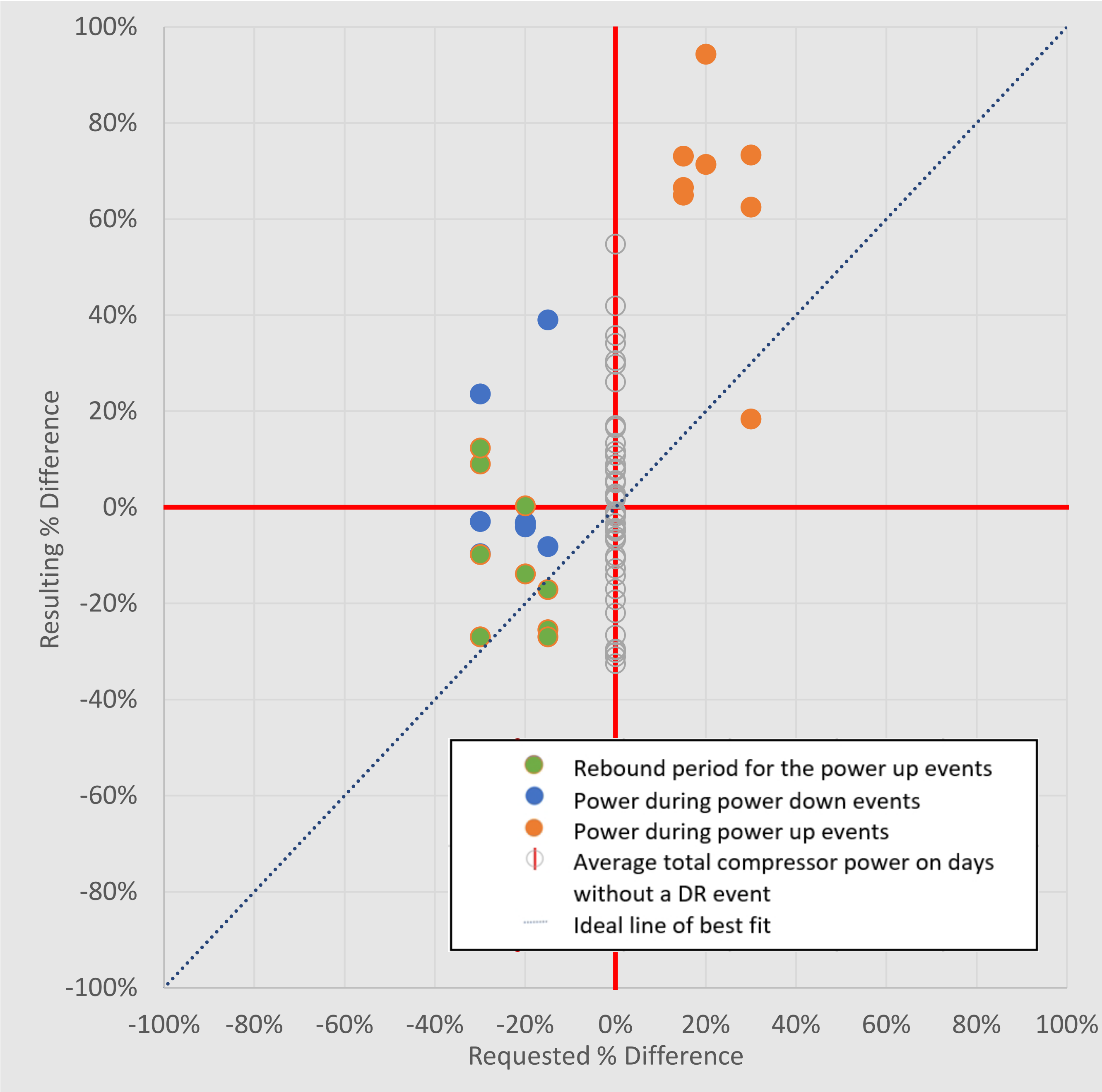
Experimental Results and Analysis—Calibration

The team successfully completed all tests without operational disruptions to the bi-directional communications path (the VTN signal produced the expected system response, and the system reported status correctly to the VTN) or to plant operations.

Quantification of the power-up and power-down field test outcomes showed potential for successful demand flexibility, with up to 27 percent total compressor demand reduction and up to 100% demand increase, compared to the baseline. Power-up events produced a strong response, while power-down events produced lower-than-expected response.

Figure G-9 summarizes the total compressor power that resulted from each DR event versus the requested amount. Orange circles are the total compressor power during power-up events, blue circles are power-down events, and green circles are the rebound period for the power-up events. Grey circles are the average total compressor power on days without a DR event. These points show the daily variability in data and the possible noise in the outcomes.

Figure G-9: Total Average Power Results

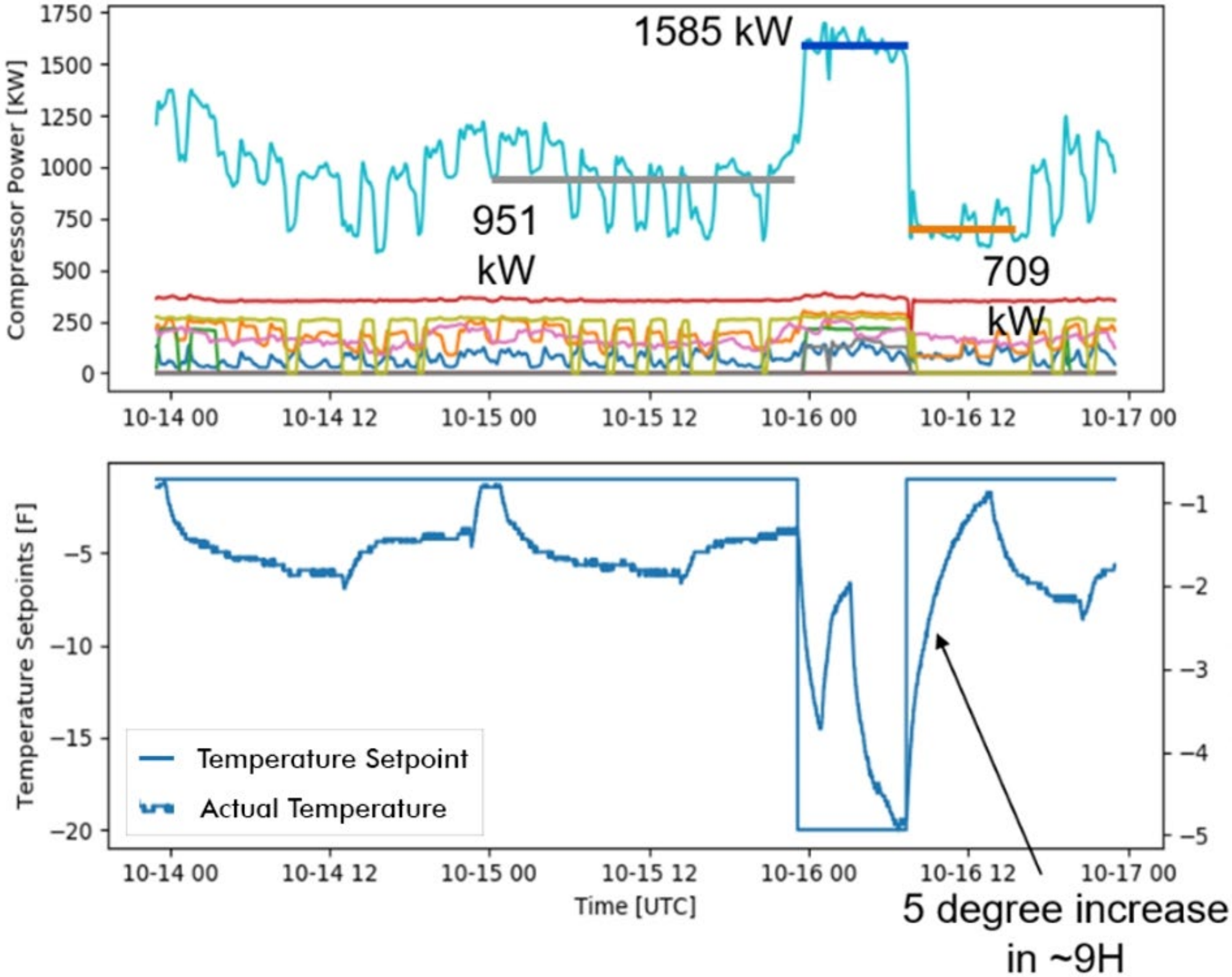


The total compressor average power results were not ideal, showing asymmetry in the results.

Source: EPRI

An ideal result would be a reduction in compressor power after the pre-cool period of approximately the same magnitude as the increase in power during the pre-cool period. However, this is not the case for all events. Overall, the response is not symmetric, as there is less response during power-down events compared to power-up events. Figures G-10 and G-11 show that many factors may contribute to the asymmetry. In both cases, a defrost event occurred during the middle of the pre-cool period, which the sudden rise in temperature shows. Also, compressor operations may vary due to other loads at the site, because DR events do not control other rooms on the site that may be interconnected to the same refrigeration system.

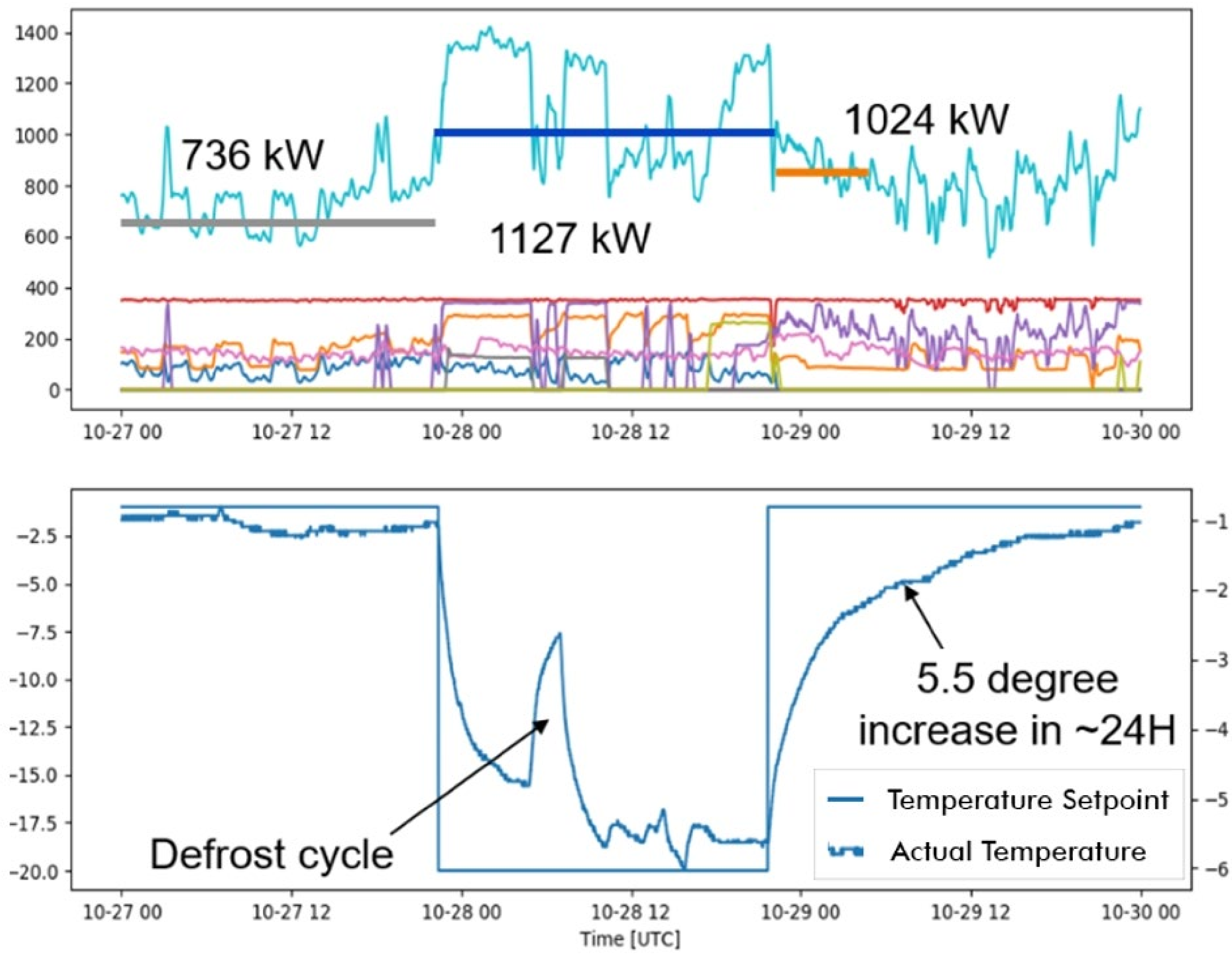
Figure G-10: Example Results Aligned with Expectations



This event was aligned with expectations, with a 25% reduction during the rebound (event #5 from October 13, 2020 to October 16, 2020).

Source: CrossnoKaye

Figure G-11: Example Results Below Expectations



This event was below expectations, with a 39 percent increase during the rebound (event #8 from October 27, 2020 to October 30, 2020)

Source: CrossnoKaye

Table G-3 shows selected results according to compressor type. Across all events, the results varied significantly. This is due to many uncontrollable factors:

- The quantities and temperatures of food masses entering and exiting the facility are unknown.
- The experiment only controlled the frozen rooms (4 of the 12 total rooms); loads in other rooms and heat gains may have impacted the temperatures as well.
- Operation of the facility is not completely automated or monitored. Areas such as the heated floors, office spaces, and the high-pressure pasteurization processes were not monitored during this experiment.
- The setpoint was changed manually, and not all doors to the rooms are automated.
- Other data, such as occupancy and shipment times, were not available for analyses due to confidentiality.

Table G-3: Example Compressor Power Data Per Event

Event #	Compressor	Avg. Power-Up Power (kW) (Pre-Cool Period)	Avg. Power-Down Power (kW) (Rebound Period)	Baseline (kW) (Avg 24hr before setpoint change)	Power Up (Pre-Cool) % Difference	Power Down (Rebound Period) % Difference
TEST	Shared Compressors	958	485	617	55%	-21%
	Frozen Room	424	114	180	136%	-36%
	Blast Compressors	160	151	153	4%	-1%
	Average Total Compressor Power	1,542	750	950	62%	-21%
1	Shared Compressors	800	549	557	43%	-1%
	Frozen Room	432	141	156	177%	-9%
	Blast Compressors	168	154	160	5%	-4%
	Average Total Compressor Power	1,400	844	873	60%	-3%
2	Shared Compressors	668	543	547	22%	-1%
	Frozen Room	339	87	159	113%	-45%
	Blast Compressors	157	166	159	-2%	4%
	Average Total Compressor Power	1,164	796	865.9	34%	-8%
3	Shared Compressors	595	564	549	8%	3%
	Frozen Room	319	113	167	91%	-32%
	Blast Compressors	115	107	153	-25%	-30%
	Average Total Compressor Power	1,028	783.7	868.5	18%	-10%
4	Shared Compressors	695	603	550	26%	10%
	Frozen Room	504	163	149	239%	10%
	Blast Compressors	173	155	146	19%	6%
	Average Total Compressor Power	1,372	921	844.2	63%	9%

Source: EPRI

Nine ammonia compressors served different rooms, and the power was monitored for each compressor. When individual compressor power was analyzed, the two compressors (#5 and #8) serving the four frozen rooms exhibited a stronger response, compared to the average total compressor response. For all the power-down events, average total compressor power varied from a 21 percent reduction to a 39 percent increase, compared to the baseline. The frozen room average compressor power varied from a 45 percent reduction to a 21 percent increase, compared to the baseline. Similarly in power-up events, the frozen room compressors exhibited a stronger response. The DR event produced an 18 percent to 100 percent increase in total average compressor power, which resulted in a 91 percent to 239 percent increase in frozen room average compressor power. However, the noise did not explain the asymmetry, so a better understanding of system dynamics is needed.

Using those equations, the team calculated the extra pre-cool energy, energy reduction, and energy penalty for each event. The team used these results to calculate the amount and percentage of energy lost for each DR event from the extra pre-cool energy shown in Table G-4. Since each event varied in duration, the team used the energy penalty percent difference from the baseline as the main metric for comparison. Using each event duration to obtain a weighted average across all DR events, the team calculated an 86 percent energy penalty compared to the baseline (86 percent more energy was used during DR events, compared to normal operations).

Table G-4: Energy Penalty Results

	Energy Used (kWh)				
Event #	**Extra Pre-Cool Energy (kWh)**	**Energy Reduction (kWh)**	**Energy Penalty (kWh)**	**Energy Penalty (% Difference to Baseline)**	**Event Duration (Hours)**
Test	14130	-4787	9343	66%	24
1	1220	-144	1077	88%	5
2	6337	-562	5775	91%	8
3	184	-85	99	54%	1
4	607	76	683	113%	1
5	5177	-1937	3240	63%	8
6	68	-84	-16	-23%	1
7	71	-25	46	65%	1
8	9098	2300	11398	125%	8
9	1023	92	1115	109%	1
10	4765	-115	4650	98%	5
11	4315	-1109	3206	74%	8
12	3223	-730	2493	77%	5
13	171	1270	1442	842%	1
14	3471	-218	3253	94%	5
15	4146	-1498	2647	64%	8
16	566	18	585	103%	1
17	2513	-850	1663	66%	5
Duration Weighted Average				**86%**	

Source: EPRI

This significant amount of energy loss can be due to a variety of factors. The plant is already optimized to operate under certain conditions and is already very efficient without much "room" for changing setpoints. Ramping up the compressors may impact the efficiency for pre-cooling during the events. Figures G-10 and G-11 show that additional cooling may also trigger defrost cycles, which can further reduce compressor efficiency. In addition to this, the refrigeration plant is not completely insulated, so that colder air can escape through open doors and heat can be transferred through the floors and walls, with higher-than-normal losses.

Overall, these results show that a demand reduction of over 20 percent is possible and a demand increase of 20 percent is possible in the compressor loads. However, there is a high cost for each event, with an 86 percent energy penalty observed across all events.

APPENDIX H:
Details of Modeling Analysis of Refrigeration Site Frozen Rooms

To obtain a better understanding of the dynamics of temperature versus chiller operation in the warehouse frozen chamber, the team constructed a numerical model. This appendix summarizes this model.

The model captures the essential heat transfer processes, as follows:

1. The heat transfer from the air to the refrigerant at the evaporator, $\dot{Q}_{evap}$
2. The heat transfer from the food to the air, $\dot{Q}_{food}$
3. The heat transfer from the warehouse floor to the air, $\dot{Q}_{floor}$
4. The heat transfer from the warehouse walls to the air, $\dot{Q}_{walls}$

Air temperature T_{air} couples all heat transfer processes, via the equation:

$$\dot{T}_{air} = \frac{1}{c_{p,air} M_{air}} \left(-\dot{Q}_{evap} + \dot{Q}_{food} + \dot{Q}_{floor} + \dot{Q}_{walls} \right)$$

The heat transfer rate from the air to the refrigerant, at the evaporator, can be approximated as:

$$\dot{Q}_{evap} = h_{evap} A_{evap} (T_{air} - T_{sat})$$

where:

- h_{evap} is the convection coefficient between the evaporator fins and the air
- A_{evap} is the total surface area of the fins
- T_{sat} is the saturation temperature of the refrigerant (ammonia, NH_3) at the set evaporator pressure

The convection coefficient h_{evap} depends on the fan speed and functions as the temperature control mechanism for the system.

The heat transfer rate from the food to the air be approximated as:

$$\dot{Q}_{food} = h_{food} A_{food} \left(T_{food} - T_{air} \right)$$

where:

- h_{food} is the natural convection coefficient between the palletized food and the air
- A_{food} is the total area of the palletized food (assumed to be composed of cubes of approximately 1 m/3 ft per side, with the same density as ice)
- T_{food} is the temperature of the food, assumed to be uniform for simplicity

In reality, the Biot number for a food pallet under typical conditions is on the order of unity, so strictly speaking, its temperature should not be considered uniform. However, it is still a reasonable approximation for the purposes of this analysis. The evolution of T_{food} is thus governed by:

$$\dot{T}_{food} = \frac{-\dot{Q}_{food}}{c_{p,food} M_{food}}$$

where:

- $c_{p,food}$ is approximated by the heat capacity of ice.
- The mass of the food M_{food} is a known parameter provided by the plant operators.

The heat transfer rate from the floor to the air is approximated by:

$$\dot{Q}_{floor} = U_{floor} A_{floor} \left(T_{floor} - T_{air} \right)$$

where:

- U_{floor} is the heat transfer coefficient between the ground under the building and the air above the floor.

This parameter results from the combined effect of the floor insulation and the air boundary layer just above the floor. The temperature of ground air under the building is maintained to just above freezing by electric strip heaters that prevent the ground from freezing to avoid damage to the building. For simplicity, assume that this temperature is a known constant.

The heat transfer rate from the walls to the air is approximated by:

$$\dot{Q}_{walls} = U_{walls} A_{walls} (T_{env} - T_{air})$$

where:

- U_{walls} is the heat transfer coefficient between the outside environment and the inside air, resulting from the wall insulation and the boundary layers inside and outside of the warehouse walls and roof.
- T_{env} is the temperature of the environment outside of the warehouse.

For simplicity, assume that this temperature is constant for a given period of a few days, and is equal to the average daily temperature.

Temperature control is a proportional integral, according to:

$$h_{evap}(t) = K_p + K_i \int_0^t \epsilon(\tau) d\tau$$

where:

- The tracking error $\epsilon(t)$ is given by $\epsilon(t) = T_{air}(t) - T_{set}(t)$
- $T_{set}(t)$ is the room temperature setpoint at time t
- with the constraint that $h_{evap}(t) \geq 0$

The constants K_p and K_i are tuned in the model to obtain realistic temperature control performance.

Table H-1 shows the physical parameters of the problem, which are calculated or plant operators provide.

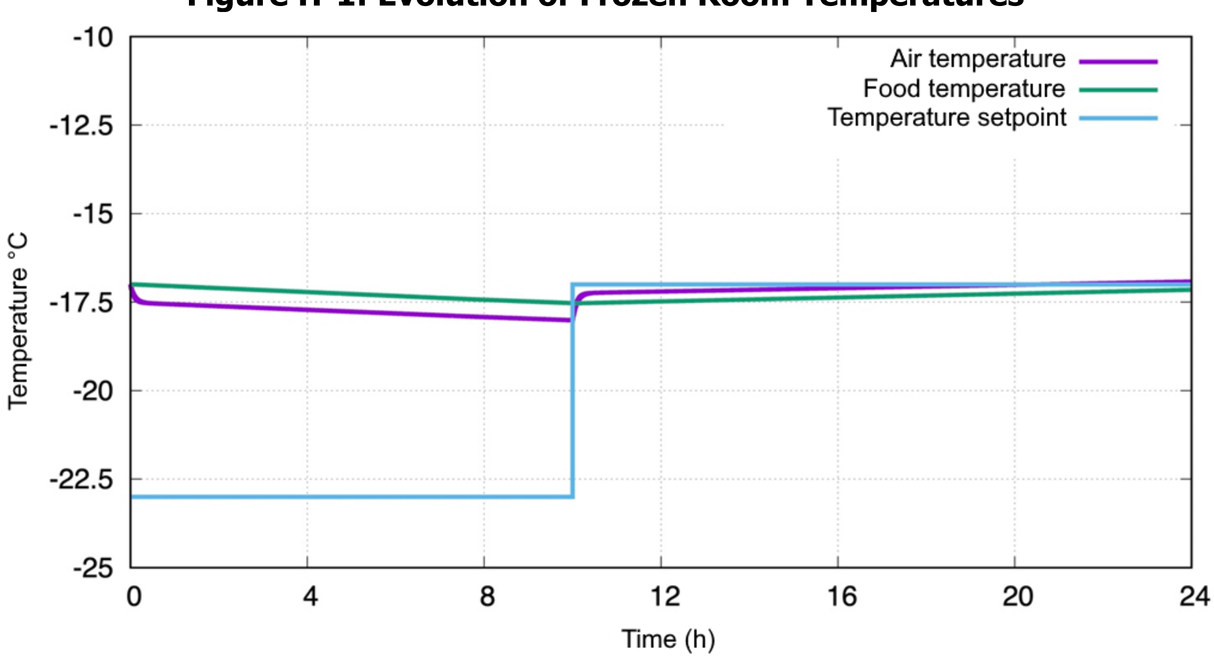
Table H-1: Physical Parameters of Modeling Analysis

Parameter	Units	Value	Parameter	Units	Value
$\boldsymbol{T_{sat}}$	°C	-29.44	U_{walls}	W/m²°K	0.1
$\boldsymbol{M_{air}}$	Kg		A_{walls}	m²	10,000
$\boldsymbol{A_{evap}}$	m²	600	T_{env}	°C	30
$\boldsymbol{M_{food}}$	Kg	6,300,000	$c_{p,food}$	J/kg°K	2050.0
$\boldsymbol{A_{floor}}$	m²	10,000	$c_{p,air}$	J/kg°K	1003.5
$\boldsymbol{U_{floor}}$	W/m²°K	0.15	T_{init}	°C	-17

Source: EPRI

Figure H-1 and Figure H-2 show the output of the simulation for a period of 24 hours. The temperature setpoint is set to -9° F (-23°C) for the first 10 hours, then returned to 0°F (-17°C) for the remainder of the time. The temperature of the air drops rapidly for a short time, approximately 30 minutes, then follows a slow, essentially linear decline. The temperature of the food, on the other hand, declines linearly for the entire time, following the same rate as the long-term decline of the air temperature. When the setpoint is returned to its original value of 0°F (-17°C) at hour 10, the air temperature quickly regains several degrees, almost returning to the initial condition, and then begins a linear increase. The food temperature inverts its linear decline and begins a slow linear increase.

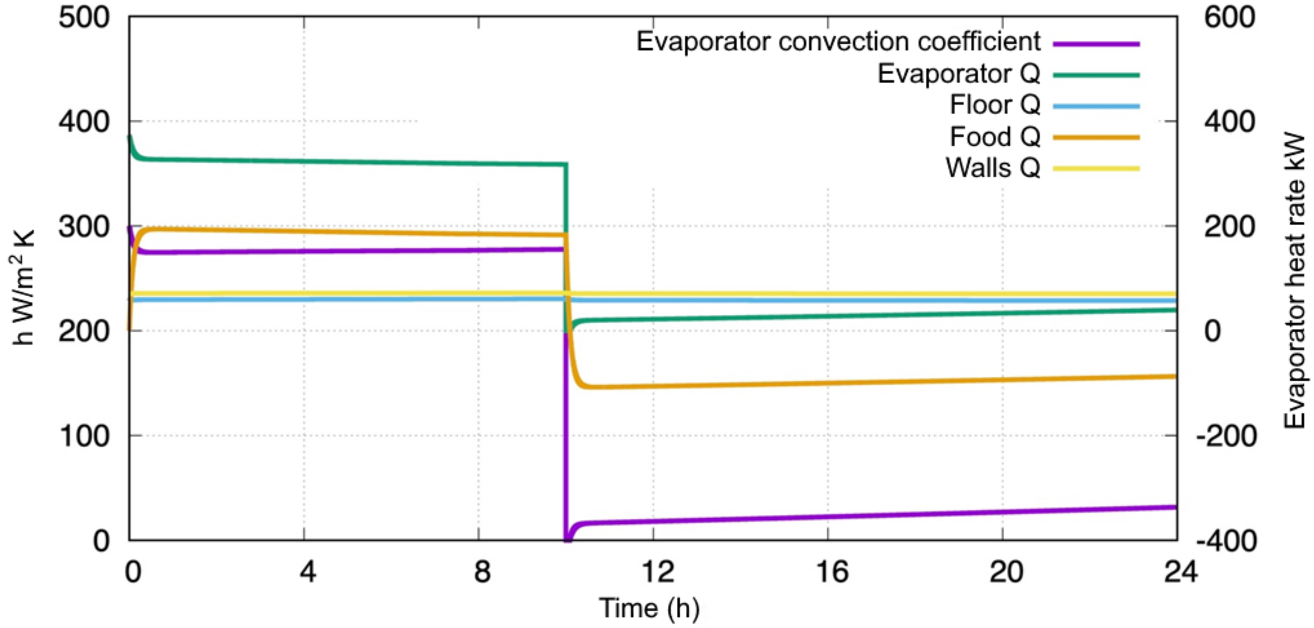
Figure H-1: Evolution of Frozen Room Temperatures



Graph showing the temperatures of a modelled frozen room during a DR temperature setpoint reset.

Source: EPRI

Figure H-2: Evolution of Heat Transfer Processes



Graph showing the model of a heat transfer process between frozen room components during a DR temperature setpoint reset.

Source: EPRI

The explanation for this interesting behavior can be found by considering the evolution of the individual heat transfer processes, $\dot{Q}_{evap}$, $\dot{Q}_{food}$, $\dot{Q}_{floor}$ and $\dot{Q}_{walls}$. $\dot{Q}_{evap}$ begins at around 375 kW, then rapidly and exponentially declines to 326 kW. This is primarily a consequence of the control mechanism, whose proportional element is reduced as a consequence of the reduced tracking error, while the integral component increases slowly. At the same time, the food starts to transfer heat to the air as the temperature of the air drops, giving rise to the characteristic slow quasi-linear decline. The floor and wall heat transfer rates do not change appreciably, remaining at around 60-70 kW.

When the setpoint is reset to its original value of 0°F (-17°C), at hour 10, the heat flow from the evaporator stops for a short time, while floor and wall heat flows quickly result in an increase of air temperature. After the air becomes warmer than the food temperature, there is a net transfer of heat from the air to the food. As the tracking error reverses sign and becomes much smaller in magnitude, the integral component of the controller becomes dominant. As a consequence, the fans turn on again, at a low capacity, so that the evaporator continues to absorb heat from the air, even though the air temperature is slightly lower than the setpoint.

This behavior is similar to that observed in the experiments.

In conclusion, the modeling provides insight into the observed experimental behavior of the system. This behavior is a consequence of multiple drivers, including the heat transfer processes between the various components of the system and the dynamics of the PI controller.

APPENDIX I: Floor Heater DR Results and Details (Refrigeration)

This appendix describes the details of the floor heater DR experiment.

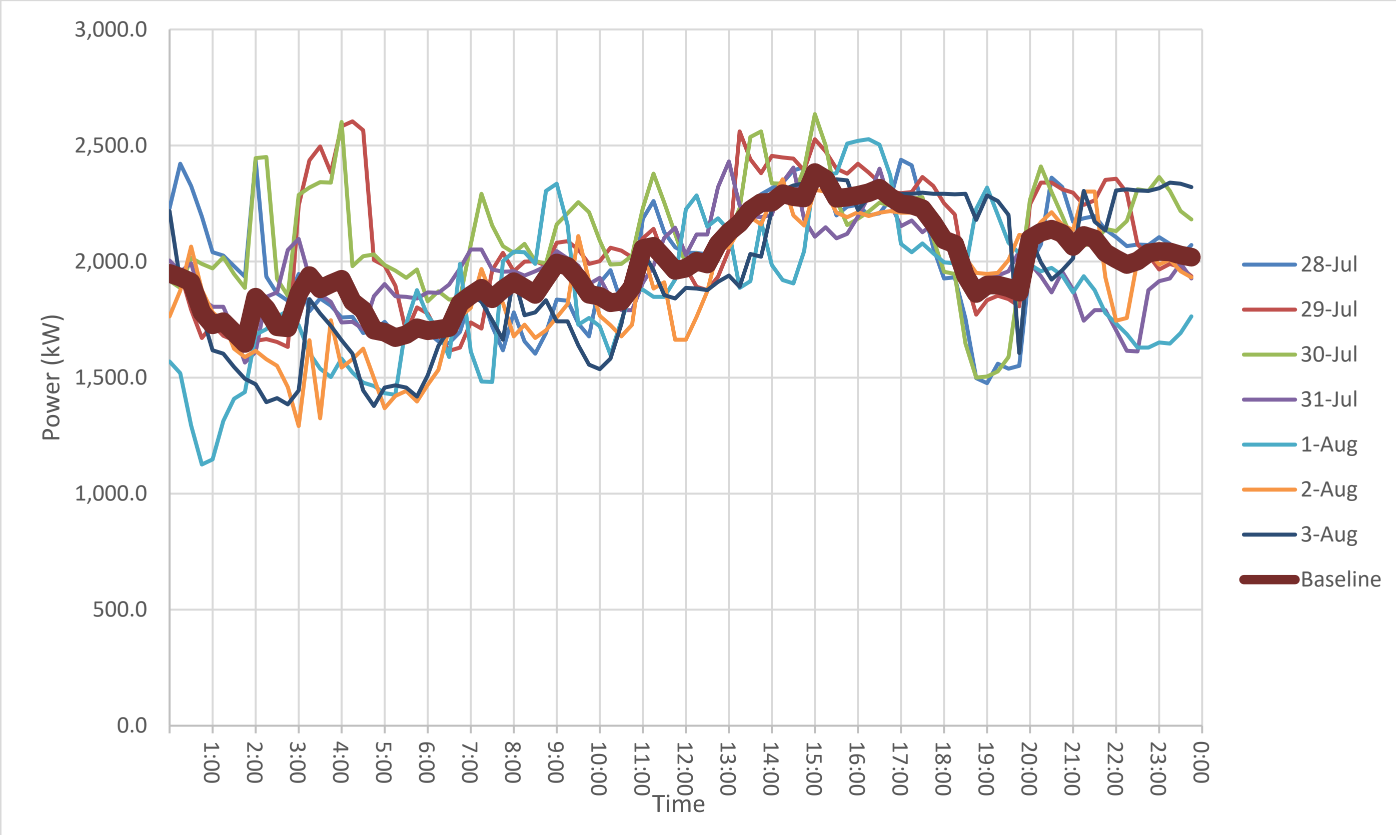
Table I-1 shows the summary of results per floor heater room/zone. Figure I-2 shows the baseline development of the experiment using the entire site meter data. This involved averaging power of seven days of data before the DR event was scheduled to form the baseline load shape. Figure I-3 shows a histogram of the seven-day data difference to the average baseline, including the standard deviation and variance of the day-to-day entire site power data.

Table I-1: Calculated DR Event Results

Room	Maximum Operating Power Based on CT Monitors (kW)	Power (kW) Saved 5 to 6 p.m.	Power (kW) Saved 6 to 7 p.m.	Average Power Saved (kW)
Room 4A	20.9	0.0	0.0	0.0
Room 4B	12.8	3.7	3.7	3.7
Room 4C	14.7	14.7	14.7	14.7
Room 5A	17.2	17.2	17.2	17.2
Room 5B	14.2	0.0	0.0	0.0
Room 5C	19.1	19.1	13.6	16.3
Room 7A	4.4	4.4	4.4	4.4
Room 7B	22.4	6.4	3.2	4.8
Room 7C	24.0	24.0	24.0	24.0
Room 7D	26.5	26.5	26.5	26.5
Total	176.2	115.9	107.3	111.6

Source: EPRI

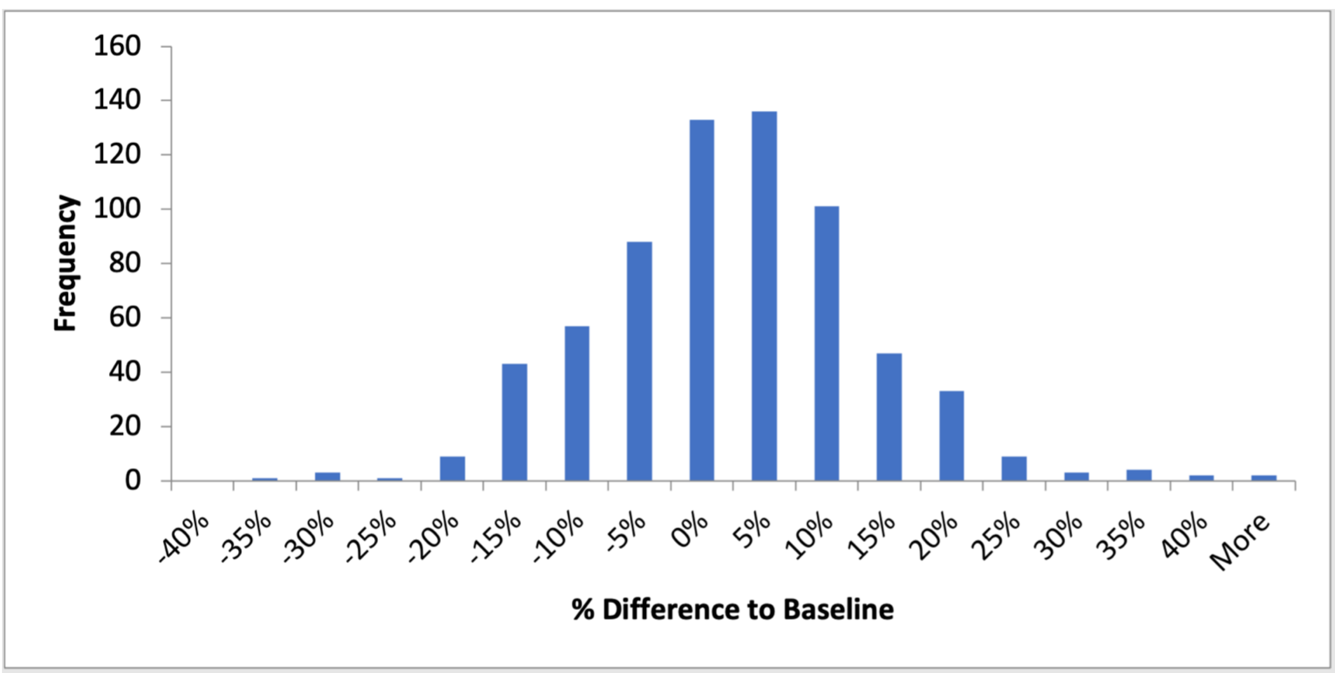
Figure I-1: Entire-Site Meter Data Baseline



Baseline development for the floor heater DR experiment using entire-site meter data.

Source: EPRI

Figure I-2. Histogram of Seven-Day Data Difference to Average Baseline



The histogram shows the day-to-day variance differences to the baseline across seven days.

Source: EPRI

An important observation was that some of the temperature sensors appeared to be uncalibrated, showing temperatures that were well below expected values. Since temperature setpoints control the floor heaters, this may cause inefficient use of the floor heaters. The average temperature data in Table I-2 show that the average temperature in Room 7D (Zone 10) is 6.8°F (25°C), with a coefficient of variance (CV) of only 4 percent from July 28, 2021, to August 4, 2021, whereas other sensors in the same room show average temperatures over 34°F (1°C). Uncalibrated sensors such as these may cause the control systems to act inefficiently since they act upon the setpoint of these sensors. Table I-2 shows that rooms/zones with average temperatures significantly lower than the normal operating 35°F (2°C) setpoint had their respective floor heaters on 100 percent of the time.

Many of the floor heaters were broken and not functioning. The operating amperage of each floor heater varied from 0-19 amps, which led to varying maximum operating power. Plant operators confirmed that some of the floor heaters required replacement. Another factor is that temperature sensors were installed at varying distances from the floor heaters, providing different temperature values due to the temperature gradient in the floor. While the DR events successfully showed the potential of flexible response, results may vary due to varying operations and efficiencies in other plants.

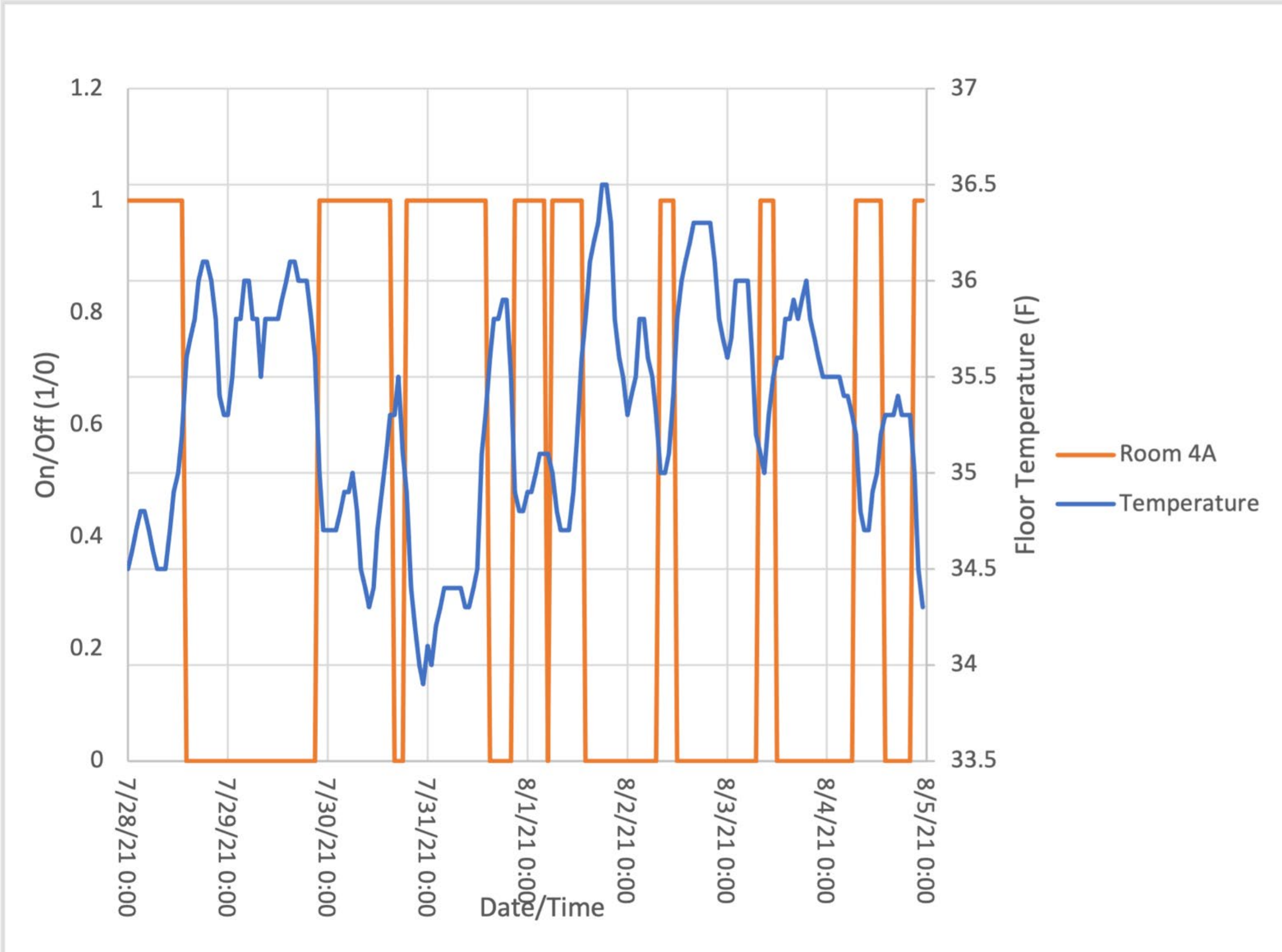
The team also analyzed temperature data of the floor sensors to ensure that temperatures did not drop to unsafe levels during the DR event. The floor sensors operated as intended, activating the floor heaters when temperatures decreased below the intended setpoint (see temperature and operation for Room 4A in Figure I-4). During the two-hour DR event, none of the temperature values decreased in any of the zones. This shows that the concrete foundation retained sufficient heat capacity to maintain its temperature over the two-hour DR period.

Table I-2: Floor Temperature Zone and Room Data from July 28, 2021 to August 4, 2021

Floor Temp Zone and Room	Zone 1 Rm 4A	Zone 2 Rm 4B	Zone 3 Rm 4C	Zone 4 Rm 5A	Zone 5 Rm 5B	Zone 6 Rm 5C	Zone 7 Rm 7A	Zone 8 Rm 7B	Zone 9 Rm 7C	Zone 10 Rm 7D
Heater % Time On	45%	46%	100%	100%	15%	91%	100%	27%	100%	100%
Average Temperature (°F)	35.30	35.16	30.68	26.78	35.34	34.92	25.62	35.40	34.23	6.81
Standard Deviation	0.60	0.15	0.15	0.09	0.17	0.14	0.10	0.22	0.08	0.28
Variance	0.36	0.02	0.02	0.01	0.03	0.02	0.01	0.05	0.01	0.08
Coefficient of Variance (CV)	1.7%	0.4%	0.5%	0.3%	0.5%	0.4%	0.4%	0.6%	0.2%	4.0%

Source: EPRI

Figure I-3: Room 4A Temperature and Floor Heater Operation



Graph showing how floor heaters in Room 4A turn on or off according to monitored floor temperature.

Source: EPRI

APPENDIX J: Track and Trending Mock-up Screen Design

To better anticipate a future DR event, the project team conceptualized a Track and Trending Tool in collaboration with DR aggregator CPower. This appendix describes the tool's graphical user's interface, including its screen design, and basic functionality.

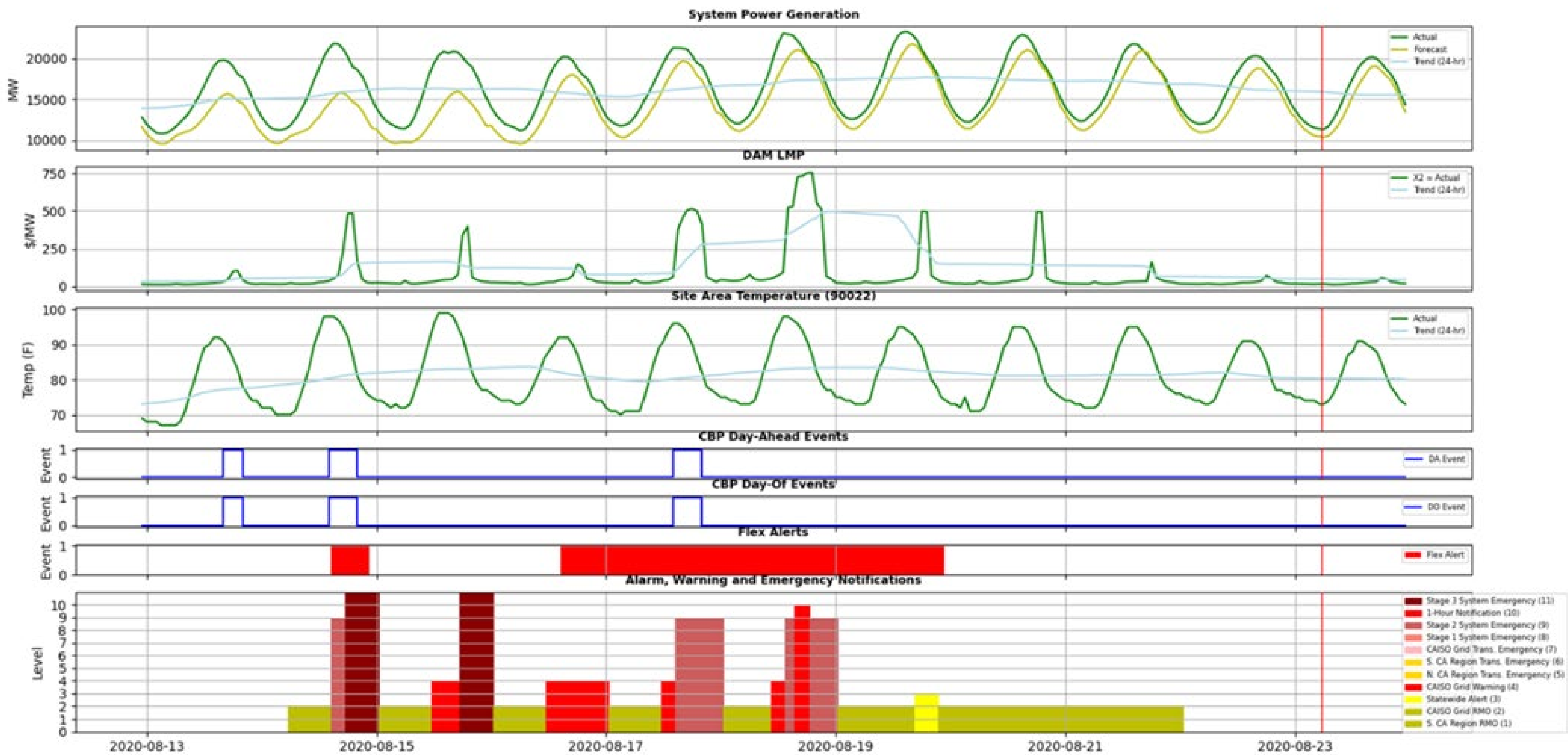
Introduction

The tool relies on conditions such as change in system-wide power demand compared to forecasts, weather conditions, fluctuation of energy prices and many other factors. The tool presents historical and forecasted data from sources including Independent System Operators (ISOs), the National Oceanic and Atmospheric Administration (NOAA), and processed information CPower collected in a common system database. The resulting datasets enable users to anticipate future DR events.

The designed layout shows related historical plots on the same time scale and stacks the plots on the same screen, enabling users to determine likely occurrence of DR events. Figure J-1 illustrates an example of a stacked layout with various data curves.

Figure J-1: Screen Design for Track and Trending Tool

SP-15 Zonal Power Generation, DAM LMP, Pump Station Area Temperature, CBP 1-6 DR Events, FA, and AWE Messages



Source: EPRI

Functional Description

The tool is designed to help users with historical and future data visualization. In the power industry, especially for DR event participants, the following data is useful:

- **Grid power generation:** Forecasting and actual grid power generation data obtained from ISOs.
- **Weather conditions:** Local temperature data downloaded from NOAA.
- **Gas prices (optional):** Natural gas market prices subscribed from Genscape or other agencies.
- **Electricity prices:** Day-ahead market (DAM) locational marginal prices (LMP) that ISOs publish and CPower forecasts.
- **Power consumption of DR participant:** DR participant's local system energy consumption data.
- **DR events:** Occurrence dates of DR events obtained from ISOs.
- **Power grid alerts, warnings and emergencies (AWE) notifications:** Various levels of AWE notifications that ISOs issue.
- **Other specific parameters** of interest to the DR participants.

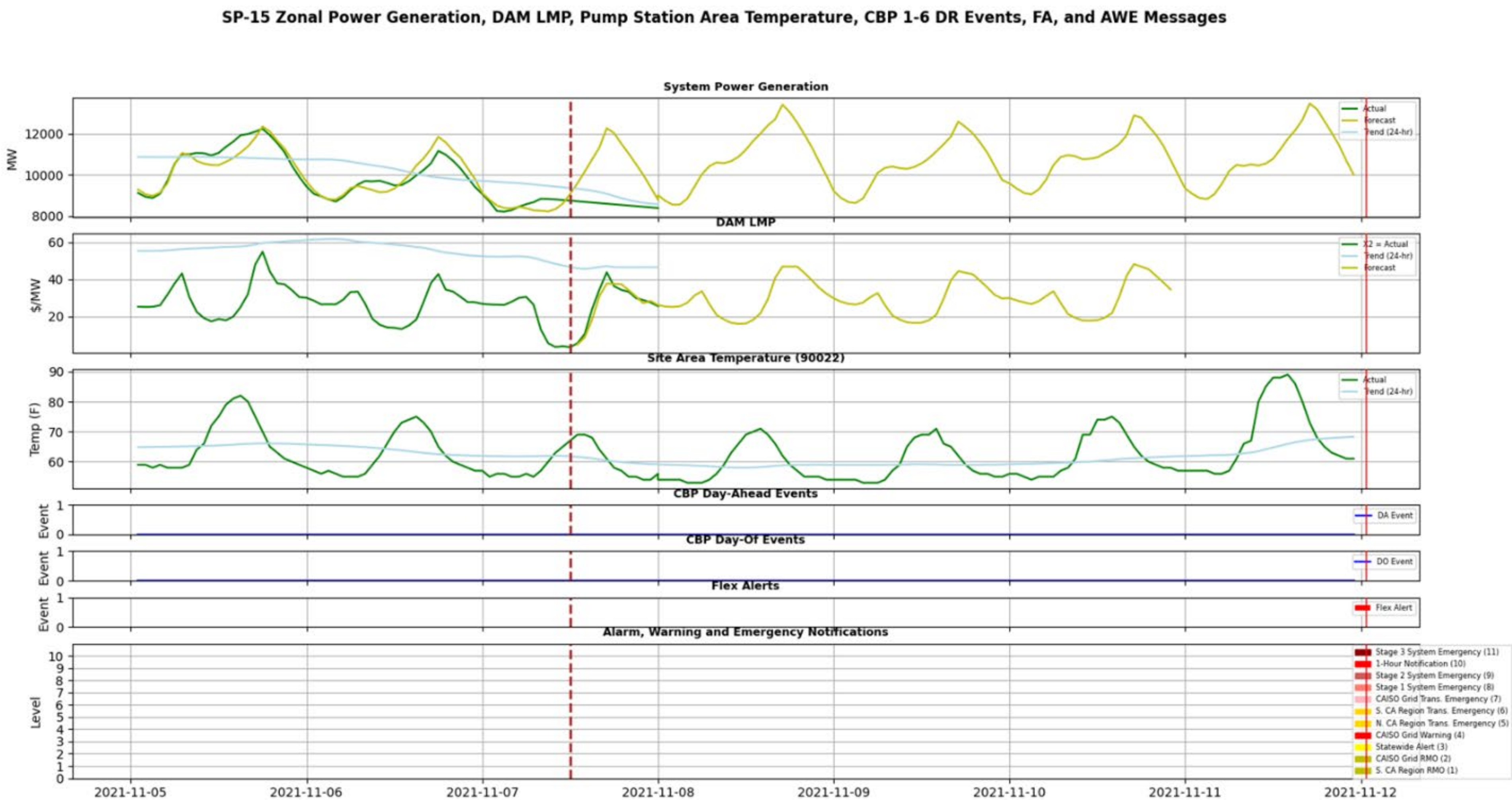
The tool presents the data in useful ways:

- The grid power generation curves show the forecasted and actual data on the same chart. To aid side-by-side comparison of data, as shown in Figure J-2, a vertical dashed line appears on the plot to separate historical (left of the line) and forecasted (right of the line) data.
- The temperature and pricing curves are shown as individual plots.
- The DR events and AWE messages are shown as bar charts, which enable comparison of historical and forecasted data at various times.
- The moving average plot helps users visualize data trends in the background for grid power generation, temperature, and electric price data curves.

The user can either enter the date for historical data retrieval, or drag with a mouse to the left or right to advance to the desired date. The thumbwheel on the mouse adjusts the magnification of data granularity. Figure J-2 shows the historical data range of November 5, 2021, to November 12, 2021. The vertical dashed line shows that the chart was generated at noon on November 7, 2021.

As shown on the right sides of of the figures, a solid vertical line follows cursor movement and provides a reference line for comparison of multiple curves. Related data values are displayed when the cursor hovers over a curve.

Figure J-2: Historical Data Range from November 5, 2021, to November 12, 2021



A vertical dashed line separates historical and forecasted data, and a solid vertical line aids comparison across curves

Source: EPRI

DR Event Anticipation

Anticipating a DR event can require processing many information sources, as well as considering specialized DR programs conditions, to better simulate results. At ISOs, human and machine decision processes were involved before issuing DR events. This tool's track and trending and stacked graphical displays use available data collected from public domains such as ISOs and NOAA, private data sources such as DR participants' local systems, and paid services such as gas prices and electricity prices. This information aids use of historical and forecasting information to prepare power systems for potential DR event occurrences.

In the figures, "system power generation" consists of forecasting and actual data. The forecasting data shows the anticipated energy requirement, which helps power generators prepare to supply the amount of energy to consumers. When demand exceeds forecasts, DR event calls are one of the options available to ISOs to alleviate demand stresses.

Extreme temperature, such as "site area temperature" in the plots, contributes to increased power consumption. Statistics show that DR events are frequently issued when temperature exceeds certain levels, increasing power consumption for cooling.

In certain parts of the country, natural gas is the primary fuel used for power generation. Fluctuation of natural gas supplies and prices impact power generation costs and capacities, increasing electricity prices.

The electricity price, such as "DAM LMP" in the plots, reflects the supply and demand condition of electric power. High electricity prices are caused by high demand for electric power in extreme temperature conditions, insufficient power supply due to under generation, transmission congestion, and increases in natural gas prices. When electricity prices increase, DR event call may be needed.

"Event" curves, such "day-ahead events," "day-of events," and "flex alerts," can be used to select the reference point when using stacked curves to study the relationship between data sets. Since all the curves are stacked with the same time scale, the synchronized vertical line is a handy tool to help users compare data.

The ISO issues "alarm, warning, and emergency notifications" (AWE notifications) when operating reserves or transmission threaten safe and reliable grid operation. A series of notifications inform market participant and the public of potential energy shortages. A DR event call is one of many tools the ISO uses to mitigate energy shortages. Tthe ISO issued different levels of AWE notifications due to changes in grid conditions and also when Capacity Bidding Program ("CBP") DR events were called. Note that many DR programs are available to the public, but the ISO issues only the selected DR events under certain conditions at certain times. DR events can be called at any time with or without AWE notification.

Users can include additional data sets, such as local system power consumption or production schedules, to the stacked curves to perform a side-by-side comparison with other data of interest.

Applications

The Track and Trending tool screen design provides a customized view of historical and forecasted data on a common time scale. Depending on application and user requirements, assuming desired data sets are available, system engineers/managers can use it to compare multiple data sets. The parameter viewing capability can also be used as a cross-referenceable data log to help site engineers troubleshoot system events if local system data sets are added. Water system operators may not be interested in power grid details or electricity prices, but are interested in temperature, DR events and AWE notifications, to keep informed of potential future DR event calls and minimize surprises. (Note that, in most cases, ISOs issue DR events and AWE notifications hour before they take effect.)

Implementation

Multiple data sets drive the stacked curves display. CPower collected these data sets from public and private sources, and stored them in the system database. Power grid generation's actual data were published hourly, while others (such as power grid generation's forecasting data, temperature, and electricity prices) were published daily. DR events and AWE notifications were published at will, which must be obtained by system polling in a fixed interval and must be updated accordingly.

CPower's proprietary DAM LMP forecaster was used to generate 4-day forecasting pricing data based on captured historical and forecasted data stored in the database. Machine leaning and linear regression were used in the forecaster to obtain forecasted results. Under normal circumstances, the forecasted results were reasonably close to actual prices. Mean Absolute Percentage Error (MAPE)[16] and Root Mean Square Percentage Error (RMSPE)[17] were about 20 percent or better. However, in extreme conditions, the MAPE and RMSPE could exceed 110 percent and 370 percent, respectively. Users can refer to AWE notifications, system operating messages, and other ISO-generated messages to further inform forecasts.

The screen design can be implemented as a secured web-based application accessible by multiple users from different remote locations. Implementation details rely on feedback from potential users to obtain more design requirements and needs.

[16] In statistics, MAPE, also known as mean absolute percentage deviation, is a measure of the prediction accuracy of a forecasting method.

[17] RMSPE quantifies the value and characteristics of errors. It measures the average percentage of the difference between actual and forecasted data.

APPENDIX K: Data Collection

This appendix describes the data collection and data processing method for the water plant field test. It describes the process of error detection and mitigation, the screen inputs and outputs for the decision support tool, the screen inputs for day-of decision making, and the decision support tool calculations.

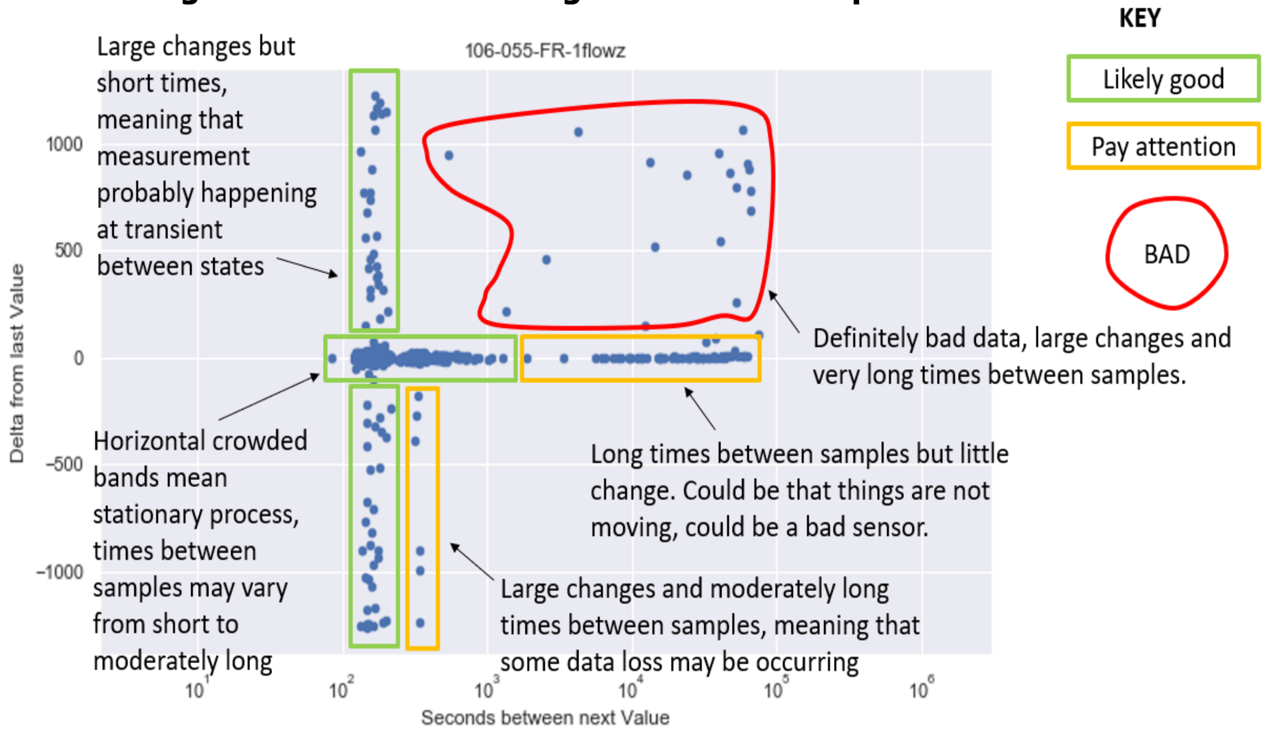
Error Detection and Mitigation

Data were collected from Zone D sensors, stored in a cloud-based database, and used to calculate flows and constraints in the system. The data collected from the zone included the pumps' power in kilowatt and gallons of water per minute (GPM) pumped. For the tanks in the zone, the height of the water in each tank is measured and stored as a datapoint in feet. The rate of change in water height is used to calculate gallons of water pumped into or out of the tank. The database only stored data when there was a change in value. Hence, missing GPM values for pumps are treated by using the last known value for each minute.

The data quality from the zone was consistent for the most part, but there were enough significant periods of missing or bad data that warranted data cleansing and processing. For tanks missing height, data is interpolated linearly every minute to avoid causing unrealistic jumps in the calculated change in volume. The criteria for removing bad or missing data examined the deltas in time since the last seen value and the magnitude of the change in the value itself. After determining normal operation for a specific pump or tank, the cut-off for bad or missing data are datapoints that fall out of the interquartile range for the measurements of seconds since the last seen value and change in value. A relatively high value for the first measurement indicates that the pump or tank value has not changed from a normally expected value in the timespan. This means the pump or tank has either been operating at the static value for that timespan, or data is missing. If the pump or tank value is not 0 and it has not changed for significant amount of time, it may be missing data. A high change in value in unison with a high number of seconds since a last seen value makes a stronger case for missing or bad data.

Figure K-1 shows a visual representation of this cleansing process **Error! Reference source not found.**for pump 106-055 FR1, and Figure K-2 shows this process for tank 106-040-TK1. After the data is processed, it is used in the decision support tool to calculate variables and constraints that aid the system operator in choosing whether to opt into a DR event.

Figure K-1: Data Cleansing Process for Pump 106-055-FR-1



Graph showing data cleansing process for pump 106-055-FR-1.

Source: EPRI

Figure K-2: Data Cleansing Process for Pump 106-040-TK-1

Graph showing data cleansing process for pump 106-040-TK-1.

Source: EPRI

Screen Inputs for the Decision Support Tool

The information screen requires the following input variables:

- **Operation speed level for the demand responsive pump**. One variable-speed well pump was enrolled for the field test study. On the user screen of the decision support tool, the supervisor can select one of the following operation speed levels: power off, power down to speed #1, power down to speed #2, or full power. Each of the speed levels is mapped into a power consumption level and water supply flowrate (in GPM at hourly resolution) generated from this well pump.
- **Aggregate supply of eight pumps estimated for the next day**. Besides the pump enrolled for participating in DR, another set of eight well pumps also contributes to the water supply in the same zone. The aggregate supply of these eight pumps is measured in flowrate (GPM) at hourly resolution. Default values are configured as the flowrates in the previous 24-hour period (actual meter readings on the previous day). The supervisor can override the default values by entering more accurate estimates into the input column.
- **Interzonal transfer estimated for the next day**. Interzonal transfer flowrate (GPM at hourly resolution) captures the amount of water entering or existing the zone that the well pump supply does not cover. Default values are set as the interzone transfer flowrates for the previous 24-hour period. The supervisor can override the default values in the input column.
- **Demand forecast for the next day**. Hourly demand estimates (in GPM) are generated from a forecast model or from supervisor inputs. Default values are initiated from the historical daily average profile for demand from July 29 to October 12, 2022. The operator can change the forecast demand profile in the decision and constraint portion of the screen to the previous day's demand profile.
- **Target storage level to recover**. The target storage level (in kgal) is the minimum level to recover by the end of the day. The default value is set as 2500-3000 kgal (about 22 ft out of 28 ft). The supervisor can override the default value.
- **Minimum storage level**. The storage level should be maintained above the minimum storage level (in kCal) throughout the 24-hour period. The default value is set as 2,000 kgal. The supervisor can override the default value.

Screen Outputs for the Decision Support Tool

Given the input variables above, the underlying calculation derives the storage tank level (in kgal) for the next-day's 24 hours, based on equation 1, which describes the relationship of the storage tank level, forecast demand, aggregate supply, and interzonal transfer. In each time step t (hour), the calculation of tank volume is given by equation 1:

$$V_t = V_0 + \sum_{i=0,\ldots,t} (F_i + A_i - D_i - Z_i)$$

- V_t is the total storage tank volume at time step t.
- F_i is the flow that the demand responsive pump generates.
- A_i is the aggregate flow generated by the other eight well pumps at a time step i from the starting time 0 to time step t.
- D_i is the demand flow at a time step i from the starting time 0 to time step t.
- Z_i is the interzonal transfer flow at a time step i.

With the water tank level calculated, Figure K-3 shows the curve of tank level in relation to the curve of water demand and the tank level thresholds, so that the supervisor can see:

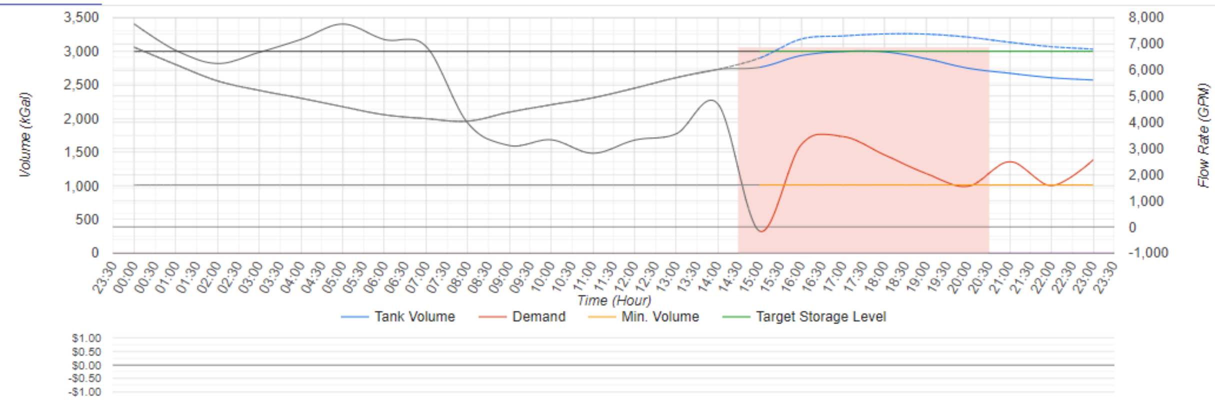
- Whether at any time of the 24 hours, the water level falls below the minimum tank level.
- Whether by the end of day, the tank level would fail to recover to the target level.

If either of these two constraints is violated, the screen displays a warning about the violation. Otherwise, the screen displays that the DR strategy selected is feasible.

Figure K-3: Decision Support Tool—Day-of Interface

Day-of Event

Operator Panel | System



4/16/2021

Current Strategy

Demand Response Event
4/16/21
03:00 PM - 08:00 PM
Power Down Event

Pump Speed Level

Speed 1

Feasible Power Down Strategy!
$0.00
Forecasted Savings

○ Opt-In ○ Opt-Out

- Max water age: 1380 (Mins)
- Min tank level: 2901 (KGal)
- Max tank level: 3259 (KGal)
- Tank recovery level: 3034 (KGal)

Save Strategy

Operator Settings

Target Storage	3000	kGal
Minimum Storage	1014	kGal
Demand Forecast	● Saved Profile ○ 4/15/2021	

Update Chart

Hour	Previous (KWh)	Strategy (KWh)	Price ($/KWh)	Savings
15:00	0	188	$0.00	$0.00
16:00	280	188	$0.00	$0.00
17:00	188	188	$0.00	$0.00
18:00	0	188	$0.00	$0.00
19:00	0	188	$0.00	$0.00
20:00	280	188	$0.00	$0.00

Time (HR)	Pump Flow Rate (GPM)	Aggregate Supply (GPM)	Zone Transfer (GPM)	Demand (GPM)	Tank Volume (Strategy) (kGal)	Tank Volume (kGal)	Tank Flow Rate (GPM)	Water Age (mins)
00:00	1,932	1,664	-139	7,762	3,061	3,061	-4,305	500
01:00	1,931	1,663	-893	6,750	2,803	2,803	-4,049	560
02:00	1,926	2,978	-979	6,251	2,560	2,560	-2,326	620
03:00	1,909	2,992	-187	6,676	2,420	2,420	-1,963	679
04:00	1,910	3,026	147	7,171	2,303	2,303	-2,088	739
05:00	1,909	3,691	155	7,756	2,177	2,177	-2,001	798
06:00	1,902	4,156	146	7,164	2,057	2,057	-960	857
07:00	1,901	4,207	168	6,898	2,000	2,000	-622	916
08:00	1,399	4,525	273	3,976	1,962	1,962	2,221	975
09:00	-625	5,309	277	3,114	2,096	2,096	1,846	973
10:00	-625	5,385	278	3,331	2,206	2,206	1,706	984
11:00	-625	5,360	482	2,820	2,309	2,309	2,397	1,000
12:00	-625	5,361	1,187	3,321	2,453	2,453	2,601	1,002
13:00	-625	5,358	893	3,563	2,609	2,609	2,063	1,002
14:00	-625	5,390	433	4,699	2,732	2,732	500	1,016
15:00	1,680	5,154	-2,294	-156 !	2,901	2,762	2,918	1,017
16:00	1,680	3,543	-1,308	3,148	3,183	2,938	989	987
17:00	1,680	3,538	-1,261	3,456	3,229	2,997	-71	1,033
18:00	1,680	3,586	-2,557	2,752	3,259	2,993	-1,723	1,084

Day-of interface for the decision support tool

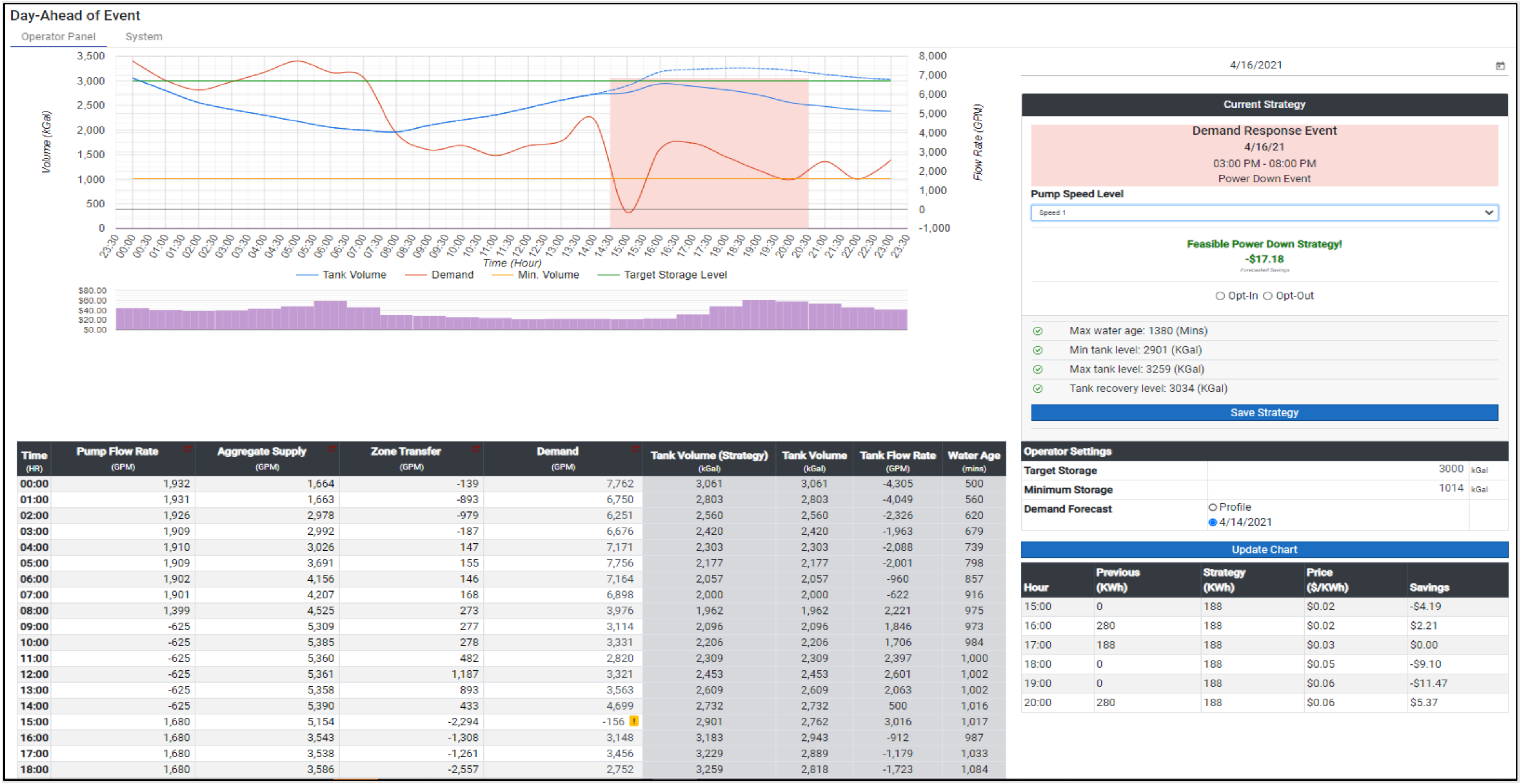
Source: EPRI

Day-of Decision Making: Screen Inputs

The system receives updates from meter reading in real-time to refresh the following variables on the day-of information screen:

- **Aggregate supply of eight pumps measured for the past hours**. On the day of the DR event, the aggregate supply of the eight well pumps (GPM) of the past hours can be obtained from meter reading. For example, at 10 a.m., the flowrate values before 10 a.m. have been measured and recorded in the system. For future hours, the operator can maintain the values inherited from the day-ahead screen shown in Figure K-4, or override the values according to the day-of situation.
- **Storage tank level measured for the past hours.** Total storage tank volume (for the three storage tanks) in kgal is updated by real-time measures of the water tank height from the site (converted to tank volume).
- **Interzonal transfer estimated for the same day.** The operator can maintain the values inherited from the day-ahead screen, or override the values.
- **Demand forecast for the same day.** The demand flowrate values use the values saved from the day-ahead screen (model forecast values, or the values modified by the supervisor day-ahead). The operator can override the values.

Figure K-4: Decision Support Tool—Day-Ahead Interface



Time (HR)	Pump Flow Rate (GPM)	Aggregate Supply (GPM)	Zone Transfer (GPM)	Demand (GPM)	Tank Volume (Strategy) (kGal)	Tank Volume (kGal)	Tank Flow Rate (GPM)	Water Age (mins)
00:00	1,932	1,664	-139	7,762	3,061	3,061	-4,305	500
01:00	1,931	1,663	-893	6,750	2,803	2,803	-4,049	560
02:00	1,926	2,978	-979	6,251	2,560	2,560	-2,326	620
03:00	1,909	2,992	-187	6,676	2,420	2,420	-1,963	679
04:00	1,910	3,026	147	7,171	2,303	2,303	-2,088	739
05:00	1,909	3,691	155	7,756	2,177	2,177	-2,001	798
06:00	1,902	4,156	146	7,164	2,057	2,057	-960	857
07:00	1,901	4,207	168	6,898	2,000	2,000	-622	916
08:00	1,399	4,525	273	3,976	1,962	1,962	2,221	975
09:00	-625	5,309	277	3,114	2,096	2,096	1,846	973
10:00	-625	5,385	278	3,331	2,206	2,206	1,706	984
11:00	-625	5,360	482	2,820	2,309	2,309	2,397	1,000
12:00	-625	5,361	1,187	3,321	2,453	2,453	2,601	1,002
13:00	-625	5,358	893	3,563	2,609	2,609	2,063	1,002
14:00	-625	5,390	433	4,699	2,732	2,732	500	1,016
15:00	1,680	5,154	-2,294	-156	2,901	2,762	3,016	1,017
16:00	1,680	3,543	-1,308	3,148	3,183	2,943	-912	987
17:00	1,680	3,538	-1,261	3,456	3,229	2,889	-1,179	1,033
18:00	1,680	3,586	-2,557	2,752	3,259	2,818	-1,723	1,084

Hour	Previous (KWh)	Strategy (KWh)	Price ($/KWh)	Savings
15:00	0	188	$0.02	-$4.19
16:00	280	188	$0.02	$2.21
17:00	188	188	$0.03	$0.00
18:00	0	188	$0.05	-$9.10
19:00	0	188	$0.06	-$11.47
20:00	280	188	$0.06	$5.37

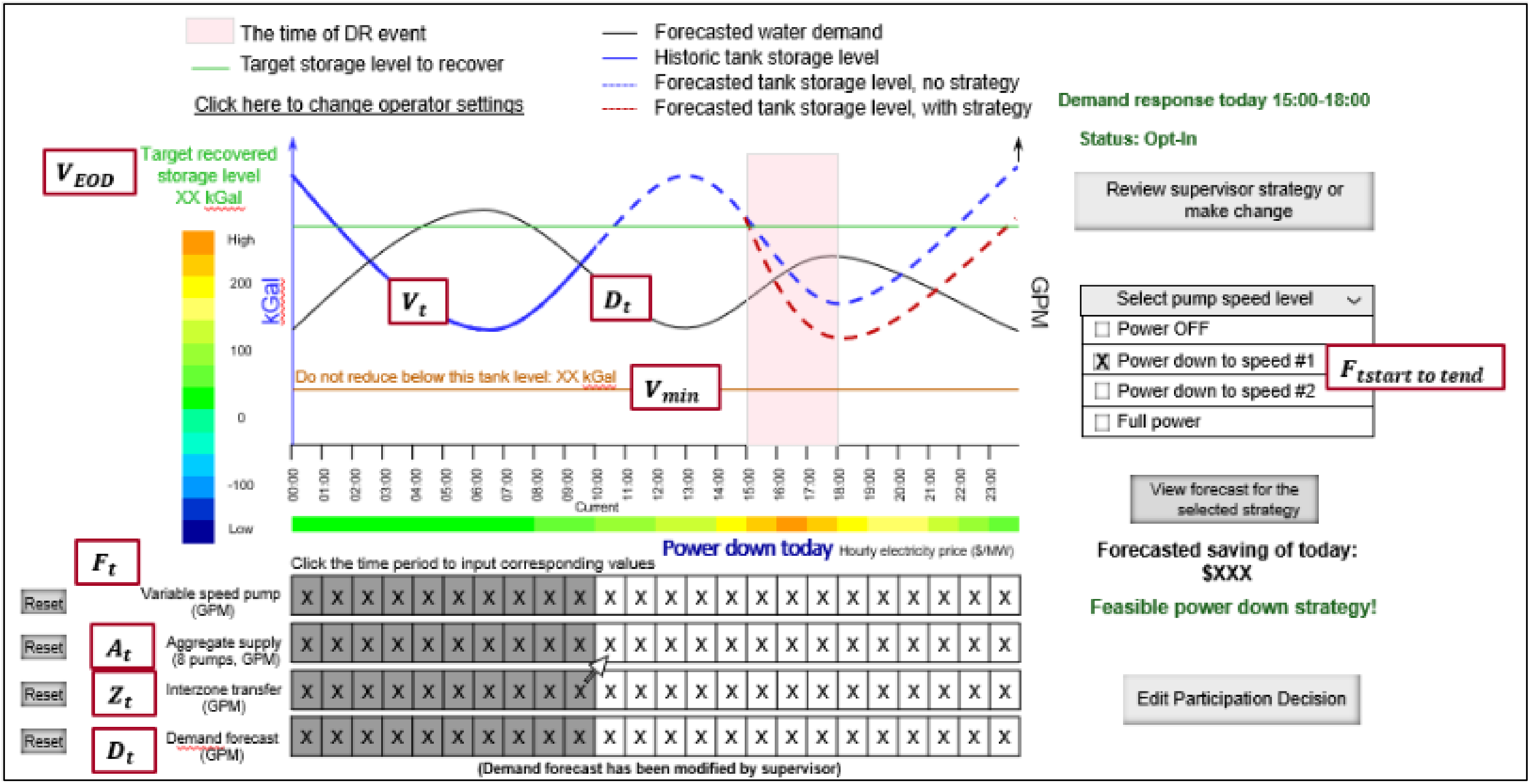
Day-ahead interface for the decision support tool

Source: EPRI

Decision Support Tool Calculations

Figure K-5 shows a detailed layout of the decision support tool screen during its design phase. The figure distinguishes the various quantities that are calculated as variables in a red box. Other buttons and features incorporated into the design are also detailed in the figure. A description of the variables and equations that are used for calculations, and constraints are defined.

Figure K-5: Decision Support Tool Concept During the Design Phase



Decision support design during preliminary design phase

Source: EPRI

Flow Rates

- F_t is the flow rate of the pump 6201 in gallons per minute at time t (positive values indicate transfer into the zone).
- F_{max} is the flow rate of pump 6201 in gallons per minute at maximum speed setting.
- A_t is the aggregate well supply flow rate at time t in gallons per minute (positive values indicate transfer into the zone).
- Z_t is the interzonal transfer at time t in gallons per minute (positive values indicate transfer into the zone).
- D_t is the demand at time t, which is the sum of Z_t, A_t, and F_t; forecasted values are from historical data, and positive values indicate water consumed within the zone in gallons per minute.
- P_t is the flow rate of the purchased water at time t in gallons per minute (positive values indicate transfer into the zone).

Tanks

- V_t is the total storage volume of all tanks at time t in gallons.
- $V_{n,\,t}$ is the storage volume of the nth tank at time t in gallons.
- V_{min} is the total minimum allowable storage volume in gallons; this value is input by the operator.
- $V_{n,\,max}$ is the maximum volume of the nth tank in gallon.
- $VEOD$ is the total storage volume to be met by the end of the day in gallons; this value it input by the operator.
- $H_{n,\,t}$ is the water storage height of the nth tank at time t in feet.
- $H_{n,\,max}$ is the maximum height of the nth tank in feet.
- $\Delta V_{n,\,t}$ is the change in volume of the nth tank during the time interval from t -1 to t in gallons per minute (positive values indicate increase in storage volume).

Assuming one-minute timesteps, it is calculated using equation 1a:

$$\Delta V_{n,t} = \frac{\left(H_{n,t} - H_{n,t-1}\right) * (Tank\ Diameter)^2/4 * 3.14 * 7.48052}{(t_n - t_{n-1})}$$

The current volume of the nth tank at time t (in gallons) is calculated using equation 1b:

$$V_{n,t} = H_{n,t} * (Tank\ Diameter)^2/4 * 3.14 * 7.48052$$

Cal Water provided the data in Table K-1 on storage tank specifications.

Table K-1: Storage Tank Specifications

Tank ID	Maximum Height ($H_{n,max}$ ft)	Diameter (ft)	Maximum Capacity ($V_{n,max}$, Gal)
106-040-TK-1	30	75.3	1,000,000
106-040-TK-3	29	76.6	1,000,000
106-040-TK-4	30	132	3,069,307

Source: Cal Water

Calculations

Assuming a time step of one minute, a mass balance is used to calculate the water demand at a certain timestep in gallons per minute. This calculation is shown in equation 2:

$$D_t = F_t + P_t + A_t - Z_t - \sum_n \Delta V_{n,t}$$

The current volume of water storage in gallons is calculated by equation 3:

$$V_t = V_0 + \sum_0^t F_i + P_t + A_i - D_i - Z_i$$

- V_t is the current volume of water storage in gallons.
- V_0 is a known initial water storage volume.

Water demand D_t at time t is forecasted based on historical water demand in zone D. For forecasted demand values, the operator can choose to use water demand from the previous day, or the average demand from July 29 to October 12 scaled by a specific factor for each month to account for monthly variations. The scaled factors were provided by Cal Water and are based on historical monthly demand from previous years. Based on information from Cal Water and analysis of historical data, there is no difference in water demand between weekdays and weekends. Hence, the average profile includes all days.

To visualize the historical data, the following data cleansing procedure should be completed:

1. Days with any missing data are excluded (input/output timeouts and "Calc Failed" errors).
2. Any storage tank data less than 5 ft (1.5 m) is treated as inoperable, and the previous minute's value is used instead.
3. Any negative flow data from sensors is treated as 0 GPM.
4. A 95 percent confidence interval is defined based on historical water demand data from July 29 to October 12. When one or more hourly demand datapoint is outside of the 95 percent confidence interval, the tool removes the specific instance of hourly demand and replaces it with the mean hourly demand from the average profile from July 29 to October 12 scaled by the factor of the appropriate month. These values have a small exclamation point within their cells to indicate substitution of out-of-bound values.

Pumping Strategy Constraints

Feasible pumping strategies in response to DR events must satisfy several constraints before the operator is able to opt in and save the strategy in the tool. These constraints are outlined.

Constraint 1: Water tank storage must remain above safe operating level

To maintain water levels at a safe operating level, the following criterion (equation 4) needs to be satisfied at any time t throughout the day:

$$V_t \geq MS * V_{min}$$

where total tank storage volume V_t is calculated in equation 3.

The recommended strategy would provide a pump speed that satisfies equation 4 with the highest amount of cost savings. In order to reduce inconvenience to the operator, this calculation assumes that only one power setting can be chosen during the entire DR event.

Constraint 2: Water tank storage recovered to the target at the end of the day

The "end-of-day" target is a value input by the operator that marks the amount of water storage that should be reached by 23:59 of the current day (equation 5):

$$V_{t=23:59} \geq V_{EOD}$$

where V_t=23:59 is calculated using equation 3 with $\mathrm{t} = 23:59$.

The strategy should ensure that it is possible to reach a storage level at the end of the day that is greater than or equal to the target end-of-day storage level, with a 20 percent margin of safety.

Constraint 3: Maximum water storage level

The total water storage V_t at any time should never exceed 4.56 Mgallons (about 90 percent of the total storage capacity) as shown in equation 6:

$$V_t \leq 4.56\ MGallon\ \forall t$$

Constraint 4: Water storage cycling within the same day

To ensure that stagnant water conditions do not persist in tanks 106-040-TK1, 106-040-TK3, and 106-040-TK4 for any length of time, water must be cycled through the tanks daily. To quantify this, the concept of "age" of the water in the tanks is used. There are two sources of "fresh" water for the tanks:

- The purchase metered via 106-040-FR3 and 106-040-FR4
- The water flowing in from the main trunk line, which can be measured via the level meters

This calculation assumes that any water entering the tanks is thoroughly mixed by turbulence with existing water in the tank. The process for calculating water age in the tanks is as follows:

Water entering the tank through purchases between time step t_n and time step t_{n-1} (equation 7):

$$V_{FR34} = (F_3 + F_4) \times (t_n - t_{n-1})$$

where F_3 and F_4 are metered flow rates provided by 106-040-FR3 and 106-040-FR4.

Water entering through the main trunk line are any positive values given by equation 8:

$$V_{TK134} = (V_t - V_{t-1}) - V_{FR34}$$

where only positive values of V_{TK134} are considered.

At any given timestep, the current age of the water in the tank is given by equation 9 and equation 10. If $V_{TK134}$is greater than or equal to zero (equation 9):

$$S_n = \left\{S_{n-1} \times \frac{[V_n - (V_{TK134} + V_{FR34})]}{V_n}\right\} + (t_n - t_{n-1})$$

If $V_{TK134}$is less than zero (equation 10):

$$S_n = \left\{S_{n-1} \times \frac{[V_n - (0.0 + V_{FR34})]}{V_n}\right\} + (t_n - t_{n-1})$$

In the unlikely scenario that the volume of water exchanged through the tank $(V_{TK134} + V_{FR34})$ is greater than the volume of water in the tank at the end of the process V_n, then the team resets the age of the water in the tank to 0. A reasonable criterion to use as the maximum allowable age of the water is one day. Also, if the volumes entering the tank are zero, then as expected, the age of the water in the tank simply goes up by one timestep.

The initial condition for the age of the water can be an arbitrary number, because its influence decays after a short time (typically a day or so), depending on water flow, and the value at the end of each day should be passed on as the initial condition for the next day. However, if the data transfer system does not allow the inter-day transfer of the water age, then use a value of 500 minutes as the initial condition. This is a relatively conservative estimate of the mean water age at the end of each day. However, there are a small number of instances when the age of water is much higher (such as up to 3000 minutes). This problem is mitigated by a flag for the condition that should be set up in the system whenever water age is higher than 1440 minutes (one day) so that operators are aware that the age conditions on the previous day were unusually high. The flag can be reset when the water age returns to zero, at which point the water has been cycled thoroughly.

Constraint 5: Avoid increasing power of other supply pumps

During the DR event, the reduction of power in the responding pump shall not cause the increased loading of other pumps in the same supply zone, so that the net consumption of power is reduced.

If constraints 1 through 4 are not met, the operator will be unable to opt into the DR event. A red “x” appears next to the constraint that is violated. The operator then needs to edit values in the data table to devise an operational strategy that satisfies the constraints. When the operator inputs an operational strategy that satisfies the constraints, the operator can opt-in and save the strategy.