Pacific Northwest NATIONAL LABORATORY

PNNL-29405

Water as a Distributed Energy Resource for California

High-level Feasibility Assessment

December 2019

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U.S. DEPARTMENT OF ENERGY

Prepared for the U.S. Department of Energy
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Executive Summary

Water systems in California are a major electricity user, and electricity costs represent a significant portion of water utilities' operating costs. Water and wastewater utilities have the capacity to shift demand in response to grid needs or price signals, and can generate power through biogas, hydropower, or onsite renewable energy systems like solar panels and wind turbines. This report points to some of the most promising opportunity areas for water and wastewater utilities to implement distributed energy resources (DERs) while also carefully laying out practical considerations.

As the grid in California has shifted to high penetrations of solar, the resulting steep net load ramps and periods of solar overgeneration create opportunities for water and wastewater utilities that did not previously exist. Water utilities can be compensated for participating in demand response offerings either directly through the California Independent System Operator (CAISO), as in the new bi-directional proxy demand response product that compensates participants for both increasing and decreasing energy usage, or through load serving entities (such as utilities, community choice aggregators, or direct access providers). For water utilities, advanced energy optimization software and excess hydraulic storage capacity in some systems, allow for enhanced opportunities to participate in demand response programs. Of critical importance are the policies, offerings, and tariffs that continue to be developed and refined. Exploratory conversations between water and electric utilities, CAISO, and the California Public Utilities Commission (CPUC) would be useful to identify and realize opportunities.

The Environmental Protection Agency (EPA) is requiring all water utilities in the country to develop risk assessment and emergency response plans to address natural disasters and malevolent acts. In response to climate change pressures, some utilities are increasing onsite self-generation while others are turning to desalination to ensure water supplies. If properly designed and implemented, resilience-focused investments at water utilities represent opportunities for coordination with electric utilities, such as through ensuring adequate storage and ensuring energy use and generating equipment is demand response enabled. Further, risk assessment planning is a prime opportunity for water and electric utilities to increase coordination, while strengthening relationships and building trust.

Finally, many water utilities are facing upward pressure on rates as revenues are down due to water efficiency measures that have been implemented over the last 30 years. At the same time, weather and fire risks are increasing and systems are aging, requiring replacement. Reducing water utilities' energy costs and providing new revenue opportunities, through synergistic coordination with electric utilities, is one way to counter the upward pressure on water rates.

The following sections identify specific opportunity areas and practical considerations.

<u>Specific opportunity areas</u>

Water and wastewater utilities have the potential to provide capacity and/or frequency response to the grid, either independently or through a third-party aggregator. Operators can voluntarily curtail grid usage by shutting down or reducing power consumption from various processes. Pumps can form a dispatchable resource that can be bid into the energy markets. With variable frequency drives, pumps can provide frequency response. Battery energy storage systems can help manage peak demand as can backup generators (fueled either by biogas,

natural gas, or diesel fuel), although emissions requirements may limit their use. If water systems are to support the grid through providing flexible supply and demand as well as ancillary services, there must be a signal, a contracting mechanism, and appropriate compensation for those services.

Hydraulic storage exists in most water distribution systems and can serve as a battery. Pumping water from treatment plants to point of use is one of the largest energy uses in water systems. Coordinating pumping and hydraulic storage in water distribution systems is another means of providing flexible or responsive demand to the energy system. In general, residential and industrial water demand has decreased due to efficiency measures, leaving many water systems overbuilt with excess hydraulic storage capacity. Excess hydraulic storage capacity can be used to manage energy use by shifting pumping loads from peak evening hours to the middle of the day when excess solar generation is available. For this type of load shifting to be practical, differences in energy pricing between peak and off-peak times must be large enough to overcome the extra effort, risk, and potential headache of changing system operations.

Energy optimization software systems exist that can minimize energy use and costs while maintaining specified pressures and water levels in tanks and storage systems. These software systems are installed on top of a water utility's existing control system and control pumps-based system conditions, tariffs, and forecasted demand. These systems can save significant energy, but require extensive utility monitoring, communication, and control systems to be in place. Many water utility operators are reluctant to turn over control of their system even though manual overrides are almost always available. For success, staff education, significant system validation and testing, and incremental roll-out for confidence building are required.

A significant opportunity for reducing electricity peak demand is through improving the efficiency of water pumps. Moving water from place to place through pumping constitutes the biggest use of energy in water systems. Past analysis performed as part of California's Operational Energy Efficiency Program (OEEP) demonstrated that some very large pumps in water systems are operating at efficiencies as low as 39% where they could be operating at efficiencies upward of 70% or more, resulting in over a million dollars in energy savings per year. Because water demand generally peaks at the same time as energy demand, pump efficiency savings would result in peak energy demand reductions.

Biogas is produced in the process of wastewater treatment, which is another key opportunity for utilities to exploit a distributed resource. Most utilities in California flare (or simply burn) some or all their biogas. Biogas can be used to heat digesters at the treatments plant, used to generate electricity, used as a vehicle fuel, or injected into natural gas pipelines. Capital requirements, low grid feed-in rates, and interconnection and permitting issues are among elements that have been identified as barriers to further biogas development. The Low Carbon Fuel Standard in California provides credits for reducing flaring and beneficial use of biogas as a transportation fuel.

Pumped-storage hydropower uses the difference in water elevation between two reservoirs to provide supply and demand flexibility to the grid. California has 3,967 MW of existing pumped-storage hydropower capacity and another 1,300 MW in development. Existing projects have changed their pump/generation patterns to take advantage of solar oversupply help mitigate the duck curve. Pumped storage systems can also provide ancillary services to the grid and perform ramping and cycling to balance renewables. For new pumped storage systems to pencil out and be cost effective, adequate compensation must be available for services provided with some level of certainty over the lifetime of the project (at least 40 years).

In-conduit hydropower is used to generate electricity from reducing pressure in water pipes. Studies have shown a California potential between 368 and 414 MW of additional in-conduit hydropower development, with significant untapped potential in the Bay Area. Economics of projects are best when generated energy can be used to offset existing water utility loads through net metering arrangements.

Seasonal pumped storage has potential to benefit the California grid as renewables increase. The Willow Springs Water Bank is a seasonal pumped storage project in development outside of Los Angeles. The project would save the State Water Project between $13 to $38 million per year by pumping water from Northern California to Southern California in the spring when rates are low and renewable generation high. Water would be banked in an underground aquifer bank for subsequent use in the summer when rates and demand are higher, resulting in significant cost and greenhouse gas emissions savings. Actualization of the project and others like it will require significant coordination, alignment of incentives, and policy certainty.

Reducing physical losses resulting from leaks in water infrastructure is another way in which water and wastewater utilities can reduce their energy consumption and increase their savings. New technologies, like advanced metering infrastructure (AMI), can support early leak detection for municipal utility-side infrastructure. Early leak detection can prevent larger, more costly leaks, enable more energy efficient infrastructure, allow utilities to more efficiently size their pipes, and better inform pipe replacement schedules.

<u>Practical considerations</u>

Water utilities take their charge of protecting the public health very seriously. They are regulated by the U.S. Environmental Protection Agency (EPA) and have specific permit requirements to which they are bound. Performance reviews for water and wastewater utilities are focused on meeting permit requirements, regardless of how much energy it takes and when that energy is expended. Energy has traditionally been a pass-through expense to customers. There is a reluctance to change. Change brings potential headaches, risks, and permit violations. Financial incentives for energy management must be clear and large enough to overcome the perceived downsides. Management support is also critical.

Many water utilities report they have not had constructive engagement with their electric utilities and/or they do not trust their electric utilities, leading to strained relationships and limited exchange of information. Assistance from outside the investor-owned utilities would be helpful, and efforts could be undertaken to increase understanding and trust between water and electric utilities. Electric utilities may also be less than enthusiastic about working with water utilities due to perceived loss of control and potential negative impact to revenue streams. These concerns must be addressed in order for constructive coordination to occur.

Finally, many utilities lack access to capital and struggle to make investments in areas outside their core mandate. Incentives and grants should be designed to support initial investments.

Next steps

Recommended next steps are for the California Public Utilities Commission (CPUC) and California Energy Commission (CEC) to work with the Department of Energy (DOE) to convene a series of exploratory meetings between water and electric utilities in California and CAISO to practical opportunities and additional coordination and research needs.

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Acronyms and Abbreviations

AMI	Advanced metering infrastructure
AMR	Advanced meter reading
AWIA	America's Water Infrastructure Act
CAISO	California Independent System Operator
CASA	California Association of Sanitation Agencies
CCA	Community Choice Aggregator
CEC	California Energy Commission
CPUC	California Public Utilities Commission
DER	Distributed energy resource
DWR	Department of Water Resources
EMBUD	East Bay Municipal Utility District
EMWD	Eastern Municipal Water District
FOG	Fats, oils, and grease
IOU	Investor-owned utility
LCFS	Low Carbon Fuel Standard
MGD	Millions of gallons per day
MW	Megawatt
OEEP	Operational Energy-efficiency Program
PAW	Pennsylvania American Water
PJM	Pennsylvania, Jersey, Maryland Power Pool
POTW	Publicly-Owned Treatment Works
RFS	Renewable Fuel Standard
SCADA	Supervisory Control And Data Acquisition
SCE	Southern California Edison
SLCP	Short-Lived Climate Pollutants
SWRCB	State Water Resources Control Board
WTP	water treatment plant
WWTP	wastewater treatment plant

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1.0 Introduction

In California, water and wastewater utilities are major energy users. A 2010 study for the California Public Utilities Commission (CPUC) estimated that statewide water sector electricity use (for supply, treatment, and conveyance) represents 7.7% of the total electricity used in the state, or greater than 18,000 gigawatt-hours per year (GWh/yr) (CPUC 2010a). When electricity consumption associated with water end uses are factored in, that number increases to 19% of total electricity use in the state, or 48,000 GWh/year (CEC 2006). A significant number of water and wastewater utilities in the United States have energy costs that exceed 30% of total operating costs (Kenway et al. 2019). Labor costs are the largest expense category for most water utilities, followed by energy costs (Haines 2019). The energy footprint of the California water sector is likely to increase as new, more energy intensive sources, such as deep ground water pumping, recycled water, and desalinization, come on line.

Although major energy consumers, water and wastewater utilities also have the potential to provide services back to the grid. California energy sector participants, such as the California Independent System Operator (CAISO), are searching for new flexible energy resources to mitigate the impacts of increased renewables. Water and wastewater utilities have the capacity to shift demand in response to grid needs or price signals, recover and generate energy, and continue to improve water and energy efficiency in operations and end use. The most significant opportunity areas for water and wastewater utilities to provide energy services are: responsive demand for capacity and frequency response through pumping system optimization and coordination with water and energy storage, pumping efficiency improvements, biogas, hydropower, and water loss reduction and efficiency.

Each of the significant areas for opportunity are described herein, along with practical considerations, industry insights, and, in some cases, potential next steps for quantifying potential. This document also summarizes water resilience efforts and associated energy implications; describes the role of incentives, support, and change management when water and wastewater utilities are considering alternative energy management practices while maintaining their focus of providing safe and reliable water at reasonable costs; and provides future recommendations.

2.0 Key Opportunity Areas

This section describes key opportunity areas for California. Key opportunity areas are defined by the extent to which the services can be provided, practicality, feasibility, and the greatest amount of value that could be produced statewide. The following sections describe opportunities associated with responsive demand, pump system efficiency improvements, biogas, hydropower, and water loss reduction/efficiency.

2.1 Responsive Demand

This report section focuses specifically on opportunities for providing responsive demand.

2.1.1 Types of Services

This section discusses two types of responsive demand that might be provided by water and wastewater utilities: 1) capacity and 2) ancillary services and regulating reserves.

2.1.1.1 Capacity

In California, electric utilities are required to demonstrate resource adequacy (RA) capacity to serve their load. Community choice aggregators (CCA) and direct access providers have the same responsibilities. In California, demand response can count as RA. Pumps can form a dispatchable resource that can be bid into the market. In order for pumps to form a demand response resource, they must typically go through a formal process with an Aggregator. A scheduling coordinator (often a utility or CCA) would be used to represent the asset for bidding into the CAISO market. This aggregated block of demand response would be a CAISO participating asset (Kristov 2019).

Revenue for participating as a demand response resource with CAISO comes through a bilateral contract with load serving entities (i.e., utilities, CCAs, and direct access providers). Load serving entities enter into agreements on a year-ahead basis and must demonstrate to CAISO in October of each year that they have sufficient resources to meet demand. Demand response resources from water utilities could be part of the resource mix. Contracts with load serving entities are good for one year and specify the number of times the resource can be called upon and how long demand will be reduced. Actual dispatch occurs through day-ahead, hourly, or real-time markets. The demand response resource gets paid for dispatch and being on call (Kristov 2019).

Water and wastewater utilities possess a variety of mechanisms through which they can provide capacity to the grid. Most water and wastewater treatment plants (WTPs and WWTPs) already have backup generators (fueled either by biogas, natural gas, or diesel fuel); therefore, they can stop using grid power and use their own generators instead, although in California there are emissions requirements that limit use of generators. Some water utilities can voluntarily curtail grid usage by shutting down or reducing power consumption from various processes. Battery energy storage systems are also being installed in certain areas to help manage peak demand and energy costs, as well as to improve reliability and resilience.

Strategic reductions in grid power usage can be based on pre-arranged agreements with utilities or third-party demand response aggregators, such as Comverge, Enernoc (now Enel X), CPower, NORESCO, or Constellation Energy Group, or in response to time-of-use rates or as a way to manage demand charges.

Wastewater plants that participate in capacity markets or demand reduction events have been able to curtail 5–40% of total plant load during an event (Sparn and Hunsberger 2015).

Wastewater utilities can provide capacity by:

- Turning off entire plants for a few hours if sufficient storage capacity exists
- Holding effluent in storage tanks before pumping it
- Delaying use of a centrifuge by collecting solid waste in a holding tank
- Reducing load for variable and multi-speed blowers (e.g., over oxygenating an aeration tank before a capacity event to ensure dissolved oxygen levels stay within limits)
- Reducing grid demand through using onsite generation with biogas (where generators are not running constantly)
- Reducing grid demand through non-biogas based onsite generators or battery storage
- A combination of strategic energy management activities managed through optimization software that optimizes based on tariffs, pressures, tank levels, and inline water quality measurements.

Water utilities can provide capacity by:

- Shutting off entire plants if sufficient storage or alternative/redundant water sources exist
- Curtailing distribution system pumping through the strategic use of system storage
- Reducing grid demand through onsite generators or battery storage
- Strategic energy management throughout treatment processes using optimization software that manages energy use based on tariffs, pressures, tank levels, and inline water quality measurements.

2.1.1.2 Ancillary Services and Regulation Reserves

As with capacity markets, there are opportunities for water systems to participate in CAISO's ancillary services and regulations reserves markets either directly, if load is large enough, or through a load-serving entity. Resources can participate in CAISO's Proxy Demand Response Program, that as of the fall of 2019, includes a new bi-directional participation model where participants can benefit from increasing or decreasing load in response to a signal, or as a reliability demand response resource. There are size, aggregator, and telemetry requirements associated with these two programs (CAISO 2019).

CPUC's Operational Energy Efficiency Program (OEEP) demonstrated that pumps fitted with variable frequency drives (VFDs) were able to change their output from 3–7% of their average kW demand over a one-minute interval, which is equal to or faster than the ramp rate for steam or combined cycle gas turbine and comparable to the average ramp rate of hydro generating plans. This capability could be used to provide ancillary services or renewable energy integration services (Cutter et al. 2011).

One example of a water utility providing ancillary services is when Pennsylvania American Water (PAW) worked with the contractor Enbala to provide frequency regulation to the Pennsylvania, Jersey, Maryland Power Pool (PJM). Enbala paid for the enabling equipment and then shared revenues with PAW. Representatives from PAW report that the payments were not large, but the risk to PAW was low, as the project was implemented at near-zero cost to the utility. Another benefit to PAW was that they were pleased to demonstrate to their regulators that they were looking at ways to reduce energy costs. PJM implemented changes to the communication protocol for telemetry and bidding between curtailment service providers (e.g., Enbala) and PJM that would have required Enbala to rewrite their software to comply with the change. This was a challenge, but one that was surmountable. However, the PJM regulation market price has dropped significantly since 2011, when the PAM/Enbala program first started. As a result, Enbala discontinued their work with PAW and shifted their focus to developing and providing demand response software that utilities themselves can run (e.g., Energy Partner) (Mosher 2019).

Various commercial products are available for aggregating different types of distributed energy resources (DERs) for providing grid services. For example, Enbala's Concerto software platform employs a real-time and distributed communications system to monitor, control, and coordinate distributed energy assets into a single dispatchable resource capable of localized voltage support, operating reserves, or frequency regulation.[1] AutoGrid, Blue Pillar, and Spirae are offering competing technologies.

2.1.1.3 Practical Considerations

Key practical considerations associated with water and wastewater utilities providing responsive demand are summarized below.

- Energy prices – Where energy costs are relatively low and do not appreciably vary by time of day, it is hard to justify significant operational changes and new investments to participate in demand response or peak shaving.
- Incentives – If a plant has backup generators and the demand response compensation is greater than the cost to run the generator, there is clear logic to participate in a demand response program; however, incentives must be large enough for water and wastewater utilities to exert the time and effort. Utilities may consider rates for per kW demand charges or going market rates for capacity services when determining the fairness of demand response compensation.
- Suitability – For pumps to provide fast load following services such as frequency regulation, the process being driven by the pump must be moderately flexible. Flexibility is required because when VFD pumps are being used for frequency regulation, the pumps may not be able to hit precise set points, such as system pressures. In addition, if the pump is being used for providing frequency control, the pump energy efficiency may be reduced. However, revenue from providing regulation services could make up for any efficiency losses (Sparn and Hunsberger 2015). Some WWTPs cannot participate in demand response because they do not have operational flexibility or the ability to reliably curtail their loads (Rulseh 2014).
- Size – One demand response aggregator says that they look for a minimum of 200 to 300 kilowatts of curtailable load in potential customers. If 15–30% of peak demand can be curtailed, a megawatt of peak demand is the smallest size some third-party demand response providers would be interested in (Rulseh 2014).
- Management support – Management support is needed if water or wastewater utilities are to adjust operations to participate in load management programs. For example, Eastern

[1] https://www.enbala.com/press_release/enbala-announces-new-release-of-its-award-winning-distributed-energy-optimization-and-control-platform/

Municipal Water District (EMWD), who plans to curtail 4 megawatts (MW) in 2019, explained that their management has made operational resiliency and flexibility a primary objective (Robinson 2019). Regulators should also be aware and supportive of participation.

- Manual overrides and operational limits – For many water and wastewater utilities, manual overrides and the establishment of threshold operational limits are prerequisites to participation in an automated demand response program.
- Air quality and emissions limitations – Although in theory a utility may be able to use their backup diesel, natural gas or biogas generator to reduce demand during peak periods, there may be air quality permit limitations that restrict the ability to do so.
- Type and timing of upgrades – A good time to consider adding demand response enabling equipment is during routine replacement and system upgrades. Incremental costs required may be small if implemented during larger upgrade projects. Water utilities may also consider working with electric utilities when designing upgrades.
- Presence of SCADA and automation equipment – Some plants respond to demand response signals by manually turning pumps down or off. However, if a utility is going to participate in a demand response program through an aggregator, participate in an automated demand response program, or utilize an energy optimization software package, utilities need Supervisory Control and Data Acquisition (SCADA) capabilities and remote control. Cybersecurity is a major consideration if third parties remote into a water utility's system.
- Financing enabling equipment – Financial support for enabling equipment (SCADA, programmable logic controller (PLCs), battery systems) is critical for many utilities due to limited capital. Some electric utilities provide incentives for water utilities to make enabling investments. Some have paid up to $300 per kilowatt of load shed for enabling equipment, which can significantly impact the cost-effectiveness (Rulseh 2014). Financial incentives need to be creatively structured to help utilities install the equipment they need to participate in demand response.
- Reasonable program design – Demand response programs and partnerships between water and electric utilities need to be workable for water utilities and not penalize them for not being able to participate in one event. Aggregators can help to spread the risk around. Without an Aggregator the downside of the fines when a utility opts out of demand response event (presumably to meet the water needs of their customers) could eliminate the opportunity. EMWD signaled that they could not take this risk alone. Several years ago, Cucamonga Valley Water District participated in an automated demand response program with Enernoc, providing over 5 MW of capacity to Southern California Edison (SCE) for up to two hours (40% of total load). They would receive 15 minutes notice and could decide whether to participate. Only once did they not participate in an event, when there were back to back events and their system still had not recovered from an event the previous day (Maestas 2019).
- In-house expertise – Staff from Cucamonga Valley Water District recommended that water and wastewater utilities have in-house staff available to enable successful participation in demand response. Upon entering into an agreement with Enernoc, Cucamonga Valley Water District held in-house trainings and phased in the initiative (Maestas 2019). Water and wastewater utilities with technical capacity and situational awareness of the electric utility industry are better suited to enter into demand response agreement than those without those capabilities.

- Sustainable business case and consistency of payments – Incentives and incremental payments for providing capacity or frequency response can change over time. EMWD participates in demand response through aggregators that is part of California's Demand Response Auction Mechanism. EMWD indicates that since 2018, the incentives being offered have "collapsed" and have been reduced by half due to a flood of bids from Community Choice Aggregators (Robinson 2019). After PAW began working with Enbala to provide frequency response to PJM, the frequency response market became saturated and the price went to nearly zero, which made the effort no longer cost effective to sustain (Mosher 2019). The business case for demand response should be calculated considering potential changes to payments and market prices.

2.1.1.4 Next Steps to Characterizing Potential

Potential next steps for characterizing the practical potential for capacity and frequency demand response in California include the following:

- Approximate power (MW) usage profile of medium to large water and wastewater utilities in California by size.
- Work with water and wastewater utility associations and electric utilities with the support of the CPUC to characterize the number of water and wastewater utilities already engaged in demand response activities.
- Estimate a low and high range for potential for capacity and frequency response by general geographic area.
- Work with CAISO to estimate the value of capacity and frequency response potential.
- Develop estimates for costs of implementing programs through equipment upgrades and training.
- Consider net benefits of a potential program in terms of dollars and greenhouse gas reductions.
- Compare costs of realizing benefits to those that could be provided through alternative means, such as batteries.

2.1.2 Beneficial Coordination between Water Pumping and Hydraulic Storage

Pumps and storage can be coordinated to provide flexibility in energy use. The two primary opportunity areas described in this section are related to 1) supply water pumping and storage and 2) treated water distribution pumping and storage. Each are described in the following sections.

2.1.2.1 Distribution System Pumping

Different parts of California require different amounts of energy for distributing water from treatment plants to points of end use. Table 1 is from a CPUC study that considered energy use intensity for different regions in California. Table 1 illustrates that some areas require far more pumping energy for water distribution than others.

Table 1. Distribution Electric Energy Intensity by Region in California (CPUC 2015)

Hydrologic Region	Topography	Energy Intensity (kWh/AF)
North Coast	Moderate	501
San Francisco Bay	Hilly	977
Central Coast	Moderate	501
South Coast	Moderate	501
Sacramento River	Flat	54
San Joaquin River	Flat	54
Tulare Lake	Flat	54
North Lahontan	Flat	54
South Lahontan	Moderate	501
Colorado River	Flat	54

Potable water distribution pumping can be coordinated with hydraulic storage to time energy use to support grid operations. Water utilities have always used hydraulic storage to handle peak water demand. Typically, maximum water use occurs between 5:00 and 9:00 AM and then again from 5:00 to 9:00 PM. Hydraulic storage tanks are usually filled from about 9:00 AM to 1:00 or 2:00 PM. Very often, water utilities do very little pumping from 2:00 to 5:00 PM. They fill tanks again from 9:00 PM to midnight and then very little pumping again occurs between midnight and about 5:00 or 6:00 AM (Sarrouh 2019).

Given proper incentives, a water utility can operate their system to store enough water, so they do not have to treat, process, or pump at peak energy demand times. Tanks can be filled in the middle of the night when system demand (including air conditioning) is lower. Water utilities are open to the idea of pumping to fill tanks during specific hours and then getting a credit for reduced use during higher net system load hours. This is already done to some extent to manage demand charges or respond to time-of-use pricing where it exists.

The larger the amount of excess hydraulic storage capacity a utility has, the more flexibility they have to time energy pumping. In general, people are using less water now than they used to due to lower flow indoor and outdoor fixtures, stricter requirements on industry, etc. As a result, many water systems are overbuilt with excess storage capacity (Brosnan 2019; Sarrouh 2019; Tesar 2019). Excess storage capacity can be used to manage energy usage. However, water age and chlorine residual must be taken into consideration. Chlorine levels must be maintained, as must phosphoric acid levels for lead and copper corrosion control. The concentrations of these chemicals decay over time, and minimum concentrations must be maintained at the point of end use.

University of California, Davis (UC Davis) is currently conducting a study to look at how water distribution utilities can use inherent flexibility to shift load to different times of day through water distribution pumping. They are working on a software program that would be used by utilities to establish when to schedule pumping. The project will also estimate the statewide capacity potential for water utilities to shift their pumping loads, by shifting pumping from peak evening hours to middle of the day using built in water storage, essentially turning distribution systems into pumped hydropower facilities that allow them to shift their loads. The project is expected to wrap up by the end of 2020. Future stages of this work will include looking at the costs associated with building additional storage tanks to supplement existing infrastructure compared to installing batteries on the grid for increased flexibility and water resilience (Miller 2019).

2.1.2.2 Practical Considerations

- Available storage capacity – Sufficient storage capacity must exist in order for a utility to pre-pump or delay pumping while maintaining minimum water levels required for worst-case “fire flow” conditions and other minimum set points.
- Water and wastewater utility willingness combined with rate structures and incentives – Operators and management of water utilities must be willing to modify operations and pre-pump or delay pumping. Willingness often depends on tariff structures and incentives. The difference in retail rates that the water utility sees between times of pre or delayed pumping and times where energy usage will be curtailed needs to be big enough to make it attractive. If they exist, demand response incentives must be sufficient. If investments are to be made, there must be assurance that compensation will persist to pay for the upgrades.
- Regulatory support and water age – The water system operators need to feel confident that regulators will not be penalize them for changing the operation of their system. Water age and associated chlorine and phosphoric acid levels must be maintained. Operators and regulators need confidence that the water level and water quality limits will not be exceeded.
- Operator comfort level and management support – Water utilities are focused on human health and safety and meeting permit requirements. Management and operators must be comfortable adjusting operations to meet energy use and energy cost targets. This is tricky, as in many cases, energy costs are a pass-through to customers, so utilities are not necessarily held to energy cost standards other than a general standard of “reasonableness” or “prudence”. Ideally, for the most durable and robust results, utility and operator energy-related goals and benchmarks should be tied to annual performance reviews and compensation.
- System design – System design of WTPs and WWTPs could be used to make processes more flexible and responsive to grid needs. Building more storage throughout the system, properly locating the storage, installing VFD-driven pumps when appropriate, and putting pumps in series would all enable facilities to better respond to the grid (Sparn and Hunsberger 2015).

2.1.2.3 Next Steps:

- Review UC Davis study results to understand technical and economic potential.
- Interview three to five water utilities to understand equipment needs, concerns, and practical considerations.
- Bring water and electric utilities together to talk about practical implementation and coordination issues.
- Work with software vendors to determine the extent to which this flexibility and optimization of storage use are currently being considered in optimization programs and where refinements or improvements may be needed.
- Determine the monitoring, control, and automation equipment needed to transition to this type of operation, and estimate costs and the percent of utilities that would need such upgrades.
- Develop bookend estimates for potential savings of modified operations given existing and potential future tariff structures.
- Compare costs and benefits based on different utility and storage sizing.

2.1.3 Pump System Optimization Software

Pump system energy optimization software also exists on the market. The energy optimization makes recommendations for operating system assets to achieve the objectives of minimizing energy used and minimizing cost of energy used while maintaining necessary pressures and water levels in tanks and storage systems. These objectives are accomplished through software that controls pumps based on modeling and monitoring of the full water distribution and control system as well as forecasted demand. In these systems, an energy management company will install a system on top of the water or wastewater utility control system. The energy management company may have their own network, and can control variable frequency drive pumps by increasing or decreasing power usage based on a signal from the utility. The use of pump system optimization software systems works well with utilities that have excess available storage capacity storage and have variable frequency drive pumps.

In November 2015, IBI Group collaborated with the Toronto Water District to optimize energy use with the BlueIQ/Toronto Operations Optimizer model. The software enhances operations of a given system by optimizing for energy while ensuring water levels in tanks, flows, pressures, and water quality are maintained. The software includes a demand forecast based on the past two to three days of consumption, present weather, and the forecasted weather. The output is a schedule of pumping operations and tank reservoir levels for the next three days or longer, if of interest. During operations, forecasted demand is compared with actual demand. If a significant difference is observed, the optimizer is re-run and the operation schedules are updated (Alidina 2019).

In the first six months of deployment, Toronto Water saved over 16 million kilowatt hours, approximately 6–10% of their energy use. Through the project, Toronto saved more than $1 million per year, which was approximately 10% of their pumping energy costs; that was <u>before</u> optimizing for time-of-use tariffs (IBI 2019). In addition to more optimally operating the existing assets, the BlueIQ program provided good insights on bottlenecks for capital improvements (Alidina 2019).

2.1.3.1 Practical Considerations

<u>Utility/operator willingness and training</u> – Implementing the new control software can be a culture change for existing staff. Many utilities and operators are relinquishing control of their pumps, even though they would be controlled within certain constraints (such as water levels or pressures), and if desired, operators could block the system from controlling equipment at certain times. Education and gradualism are required. In the Toronto example, the proposed change required significant validation, testing, and confidence building. Software deployment on Toronto Water District’s computing assets limited computing performance and required adjustments by IBI, which was kept on an annual contract to support the optimizer (Alidina 2019).

<u>SCADA and enabling technology</u> – IBI, who owns the intellectual property for the BlueIQ system (used in Toronto), recommends that customers upgrade assets to the degree they can first, before implementing an energy/pump optimization software system. SCADA, VFD, and automatic pump controllers are among the technology that is needed.

<u>Support contracts</u> – After an energy management system is implemented, it is important that utility staff have access to ongoing support. In the Toronto case, IBI was kept on an annual contract to support the optimization software.

2.2 Pump System Efficiency Improvements

Moving water from one place to another through pumping constitutes most of the energy use in water and wastewater systems. This section describes pump system efficiency improvements that could be achieved through a pump monitoring and replacement program.

Pump monitoring and replacement programs can result in significant energy savings, including at the time of energy system peak demand, and have been found to be cost effective. The CPUC initiated the OEEP to investigate options for achieving a 10% reduction in electrical power consumed by induction motors in water facilities. E3 developed an Evaluation, Measurement & Verification (EM&V) report for 17 OEEP pump sites, with 22 total pump retrofits (Cutter et al. 2011). The OEEP project supported replacing fixed speed pump controllers with VFDs and installing PLCs, efficiency optimization software, and monitoring equipment to improve operational efficiency. E3's assessment found that the full suite of measures together was not cost effective, but a standalone pump monitoring and replacement program was cost effective.

Table 2 shows E3's assessment of a pump monitoring, evaluation, and selective replacement program. Of 12 pumps evaluated, six were determined to be operating outside of their efficiency range and good candidates for replacement with some of the pumps operating at efficiencies as low as 24%. It is assumed that all pumps in these applications could achieve 70% efficiency. For one 300 HP pump operating at an efficiency of 39%, improving efficiency to 70% results in an annual energy savings of nearly $1.2 million. For the entire program, a monitoring, evaluation, and replacement program has a benefit cost ration of 1.9.

Table 2. Cost Effectiveness of a Pump Monitoring, Evaluation, and Selective Replacement Program (Cutter et al. 2011)

	HP	Starting Efficiency	Improve to	Annual kWh Savings	Lifetime NPV $	Monitorng Equipment Cost	VFD, Pump and Motor	TRC Ratio
Mojave	25	24%	70%	$46,486	$38,970	$9,000	$46,858	0.7
Jefferies	200	44%	70%	$352,706	$289,697	$9,000	$127,763	2.1
Bascom	75	61%	70%	$58,166	$50,049	$36,031	$135,145	0.3
County	300	54%	70%	$389,395	$311,002	$34,754	$146,825	1.7
Alisal	300	39%	70%	$1,167,813	$1,014,044	$24,297	$130,362	6.6
Hemmingway	30	55%	70%	$29,326	$23,020	$25,422	$35,986	0.4
Monitoring costs for 6 additional pumps not needing replacement						$138,504		
Total Program Costs and Benefits				**$2,043,891**	**$1,726,782**	**$277,008**	**$622,939**	**1.9**

Significant efficiency gains can be realized through monitoring and replacing pumps operating inefficiently. Because water demand generally peaks at the same time as energy demand, pump efficiency savings would result in peak power reductions as well.

This could be achieved through conducting periodic pump tests to find out at what efficiency pumps are operating and select appropriate pumps for given applications.

2.2.1 Practical Considerations

- Regular monitoring and pump testing – Pumps need to be tested on a regular basis. It is recommended that utilities develop a program of testing pumps. Tests can reveal when it is cost effective to replace pumps with more efficient pumps. Pump tests can also reveal which pumps, or series of pumps, are operating most efficiently under different conditions. Simple guidance can be developed in the form of pump schedules that direct operators as to which pumps (or series of pumps) they should run under different conditions (Sarrouh 2019).
- Screen and prioritize – The largest pumps that operate most frequently have the most potential to provide energy and peak savings and should be prioritized in monitoring and replacement programs.
- VFDs are not always the answer – VFDs come with an efficiency penalty of 2–5% and they cost significantly more than constant speed pump controls. The cost of VFDs in some applications are not worth the benefit. In certain cases, a highly efficient constant speed pump is better than a VFD. Constant speed pumps may be preferred where demand and water level being pumped are not highly variable, a large amount of storage exists on the system, and the pump is not being used for automatic demand response (Sarrouh 2019).
- Training and education – Operator training and follow-up is required for implementing a pump monitoring and replacement program. This needs to be done on an ongoing basis to account for turnover of staff and management. Operators and management may not have the information to conduct a pump monitoring program, and may need support with developing a plan, securing funding for the plan, carrying out pump testing, calculating potential costs and savings of replacing pumps, and communicating results to management for final decision.
- Use technologies – There are technologies that can be used to fine tune pump operations based on real-time pump and system curves.[1]

2.2.2 Next Steps to Characterize Potential

- Targeted interviews and literature review – Targeted interviews and a literature review can be conducted to establish the extent to which pump monitoring and replacement programs are already being implemented.
- Potential study – If, based on the targeted interviews and literature review, it is determined that opportunities exist, a survey-based potential study could be initiated to determine the potential for energy and peak savings available based on pump efficiency improvements.

2.3 Biogas

Biogas is generated during wastewater treatment when biological sludge is broken down via anaerobic digestion. Anaerobically digesting the wastewater sludge breaks down the organic matter and produces biogas, a mixture of methane (CH_4) and carbon dioxide (CO_2), along with some trace impurities (CARB 2014). Biogas generated from WWTPs is often destroyed by flaring (methane capture and destruction) or used in devices that generate power or electricity from the combustion. The majority of biogas producers in California currently flare their biogas (Ong et al. 2017). Biogas can also be used to heat the digesters at WWTPs, which enhances

[1] For example, Specific Energy is a company that has sensors and software that continually assess the best and most efficient way pumps should be running. They identify where the pump curves have changed and can identify when pumps are operating outside of efficiency ranges

the digestion of sludge. Biogas can also be further refined to remove CO_2 and trace impurities to near pure biomethane that can be compressed and used or sold as a vehicle fuel (onsite or otherwise) or injected into a natural gas pipeline. Generating electricity with biogas is the simplest (relative to design, permitting, and regulation) and lowest cost option for biogas utilization at existing biogas production facilities, other than heat generation with boilers (Ong et al. 2017).

A survey was conducted by the California Association of Sanitation Agencies in 2013 with over 250 California WWTPs (CARB 2014). It was determined that out of the 250, over 150 WWTPs operate anaerobic digesters to destroy part of the organic component of wastewater sludge. Approximately 90% of those facilities digesting wastewater sludge were also using the biogas to produce renewable power for plant consumption, or for export to the public grid, or both. Approximately half of those WWTPs producing power were doing so by use of internal combustion engines and generators. All the WWTPs surveyed who had anaerobic digestion said they flare the biogas at times.

Many WWTPs are oversized and have excess capacity in anaerobic digesters for agricultural wastes, fats, oils, and greases (FOG), etc. Cogeneration is when additional feedstocks are brought and added to wastewater sludges to increase the biogas production at the wastewater treatment facility. Some wastewater plants are energy net zero due to the amount of biogas produced from wastewater. The East Bay Municipal Utility District (EMBUD) is an example of a utility that practices co-digestion and is nearly net zero in its energy use (Sprang and Loge 2015). A pilot facility at the EMBUD WWTP at the base of the Bay Bridge in Oakland has converted nearly 20–40 tons a day of restaurant food scraps to electrical power (EMBUD 2019).

In 2017, the California Association of Sanitation Agencies (CASA) estimated that the wastewater sector has existing excess capacity to co-digest up to 75% of the food waste and FOG currently being landfilled (CASA 2017). Many WWTPs already have an anaerobic digestion infrastructure in place, and they are increasingly providing the option to receive hauled-in organic waste (such as FOG and food waste) to anaerobically digest it. California Senate Bill 1383, passed in 2016, establishes methane emissions reductions targets in a statewide effort to reduce emissions of short-lived climate pollutants in various sectors of California’s economy, including targets to achieve a 50% reduction in the level of statewide organic waste from the 2014 level by 2020 and a 75% reduction by 2025. Enforcement and penalties begin on January 1, 2022 (CalRecycle 2019). Where excess capacity exists in digesters, organic wastes can be diverted from waste streams to WWTPs to be co-digested with WWTP solids. Many treatment plants are located close to population centers and could potentially obtain and process a significant amount of food and other suitable waste streams. Local governments play an important role in enabling and encouraging this (CARB 2017). Permitting is extensive with any biogas facility, but even more so when co-feedstocks are included.

2.3.1 Practical Considerations

Barriers - Figure 1 shows the results of a survey conducted during a recent Water Research Foundation study on opportunities and barriers for renewable and DER development by water and wastewater utilities (Kenway et al. 2019). The figure shows the barriers to recovering energy from biogas in wastewater utilities include the following: lack of engagement with the electricity utility, poor feed-in tariff rates, interconnection of the electricity generated by the wastewater utilities to the main electric grid is difficult, and the cumbersome process of acquiring contracts for resale of electricity produced from wastewater utilities to the main grid.

Among utilities not currently capturing biogas, lack of financial/capital capacity was noted as a barrier. Among utilities already capturing biogas, permitting problems and lack of time to conduct assessments were identified as barriers (Kenway et al. 2019).

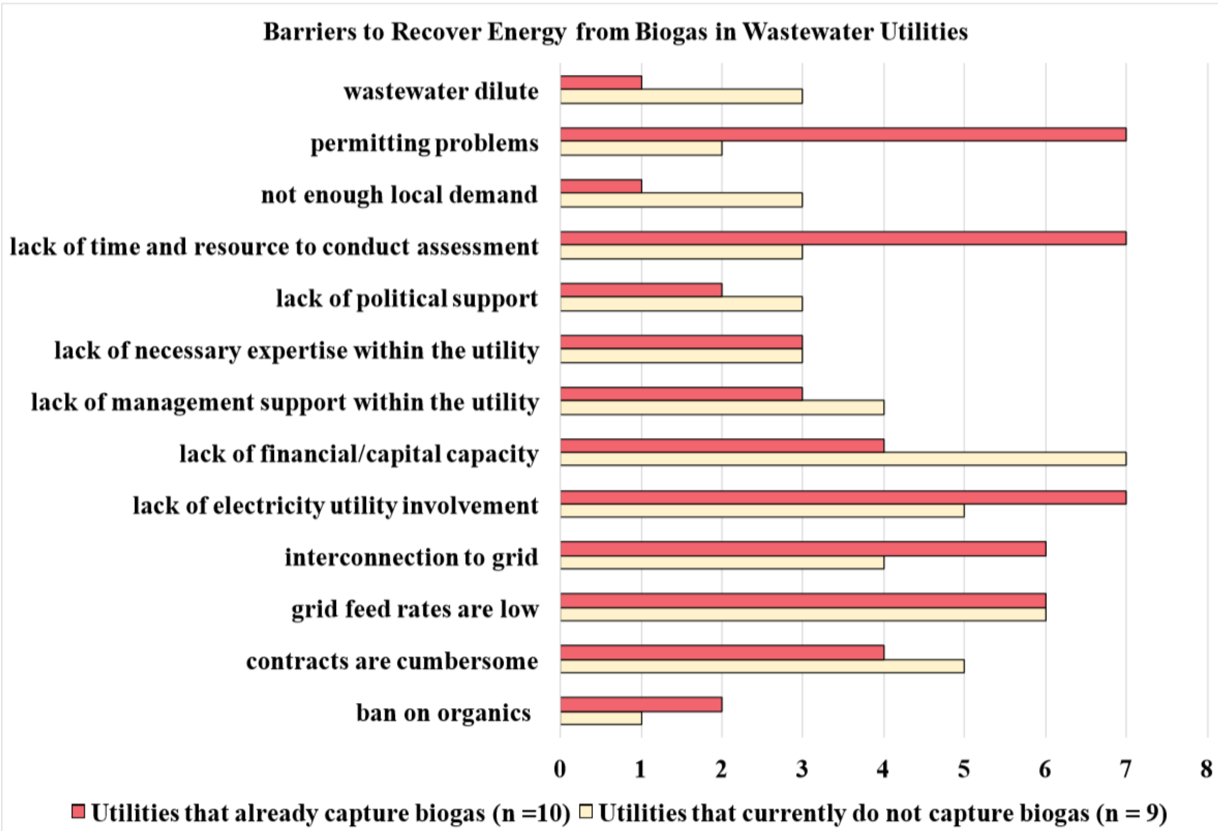

Figure 1. Barriers to Energy Recovered from Biogas in Wastewater Utilities (Kenway et al. 2019)

Interconnection – Using biogas to generate electricity is less costly than injecting biogas into natural gas pipelines, but there are still a variety of interconnection-related fees. For example, to interconnect with the Pacific Gas & Electric electricity grid, there are pre-installation costs (i.e., interconnection request fees, study/review fees/deposits, interconnection facility and system modification, and ongoing maintenance costs) and post-installation costs (i.e., standby charges, non-bypassable charges) (Ong et al, 2017). However, there are exemptions and incentives that may apply. SCE customers that propose to interconnect to their distribution system must follow their Wholesale Distribution Access Tariff under the jurisdiction of the Federal Energy Regulatory Commission, as well as their Rule 21: Generating Facility Interconnections under the jurisdiction of the CPUC (Ong et al. 2017)

Air permitting – Internal combustion engines have come under increasing regulatory scrutiny and are subject to more stringent emissions standards for stationary sources by local air districts in order to attain air quality standards. Many WWTPs are permitted to burn digester biogas through flaring and are classified as industrial facilities. Changes to this, such as capturing biogas to produce electricity through a combined heat and power system, may result in re-classifying the WWTP's purpose as a generation source, subjecting the plant to different emission compliance and abatement equipment rules. In addition, beneficially using methane from WWTPs may result in the same hurdles faced by dairy digesters and organic waste composting facilities. Policy and technical support are needed to enable WWTPs to overcome barriers and beneficially capture biogas for electricity generation, supplement natural gas pipeline fuel, or create a transportation fuel (CARB 2017). Co-digestion adds another level of permitting, reporting, and oversight requirements.

<u>Incentives and revenue streams</u> – California's Low Carbon Fuel Standard's (LCFS) goal is to reduce carbon intensity of the transportation fuel pool by at least 20% by 2030. Biogas from WWTPs can be used to generate LCFS credits. LCFS credits would be available to WWTPs for avoided flare emissions and co-generated power exported (CARB 2014). Credits are currently trading at nearly $200 (CARB 2019). Federal tax credits for biogas are available as part of the Renewable Fuel Standard (RFS). The U.S. Department of Energy's Biorefinery Assistance Program provides loan guarantees to develop, construct, and retrofit commercial-scale refineries that produce advanced biofuels (Kenway et al. 2019).

<u>Cleaning biogas</u> – Wastewater biogas requires significant treatment in order to be injected into the natural gas pipeline. Even using biogas in engines onsite can require some biogas refining. Biogas processing equipment can be expensive, although requirements for refining biogas for use in a gas-fired turbine may not be as extensive as requirements for refining biogas for use as motor-fuel or pipeline injection. A CEC study by Ong et al. reviewed current standards and technology specifications and found that California investor-owned utility gas contaminant standards for biomethane pipeline injection are comparable to those found in other states and countries, and that meeting these standards is easily achievable using conventional gas cleaning technologies; however, heating value standards in California are higher than elsewhere (Ong et al. 2017).

<u>Cleaning and consistency of co-feedstocks</u> – Co-feedstocks brought into a WWTP from outside need to be appropriate for anaerobic digestion. It has been reported that something as simple as a fork brought in could damage pumps and motors. Also, wastewater sludge is consistent from day to day, but co-feedstocks can vary quite a bit in quality and quantity as well as requirements for pre-processing. Natural gas may need to be mixed to biogas to boost methane content. Standards and lessons learned from other plants would be useful.

2.3.2 Next Steps to Characterizing Potential

- Perform interviews and a literature review to project total production, flaring, and beneficial use of biogas produced in California WWTPs
- Organize a forum for water and electric utilities and permitting entities to exchange ideas and discuss streamlining opportunities relative to biogas
- Gather information on typical gas cleaning equipment needs and costs as well as interconnection and permitting needs and costs
- Perform back-of-the-envelope calculations on benefits versus costs
- Consider other models and develop recommendations for grants or an umbrella contract to provide support to promising WWTP biogas candidates on resource potential and economic assessments
- Based on interviews with WWTP staff, air regulators, and utilities, develop concepts for streamlined permitting and interconnection forms and processes.

2.4 Hydropower

Hydropower is already a significant part of the energy picture in California. During 2018, hydropower produced electricity totaled nearly 25,344 gigawatt-hours, or roughly 13.5% of the state's total system, from 270 hydroelectric generators with an installed capacity of 14,000 MW (CEC 2019). Conventional hydropower, pumped-storage hydropower, in-conduit hydropower and seasonal pumped energy storage have the potential to provide benefits to the California grid. Pumped storage, in-conduit hydropower, and seasonal pumped energy storage are described in more detail below.

2.4.1 Pumped-Storage Hydropower

Source water extraction and delivery is a significant energy user in California. Figure 2 shows the monthly energy profiles of different water sources in California in 2010.

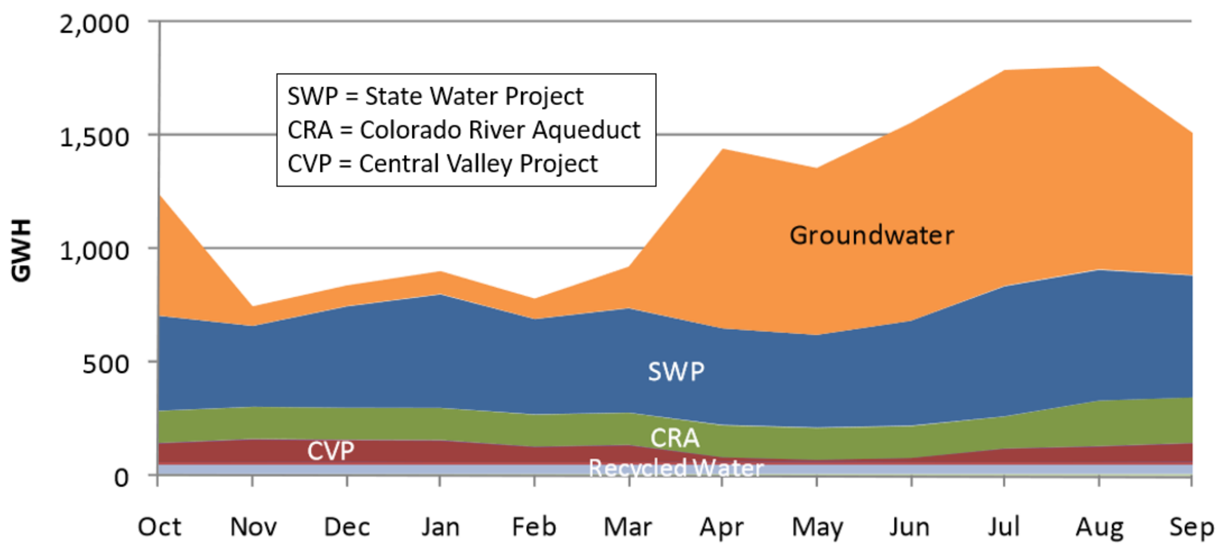

Figure 2. Baseline Monthly Energy Profile of Different Source Waters in California (adapted from CPUC 2010a)

Where pumping and storage exist, there is the potential to provide fast grid services, such as regulation, or longer services, such as capacity (Sparn and Hunsberger 2015). Coordinating large scale water pumps (including groundwater) and storage (through aboveground or underground reservoirs) is a significant energy opportunity.

Pumped storage projects store and generate energy by moving water between two reservoirs at different elevations. As of July 2016, California has seven existing pumped storage facilities, with a total capacity of 3,967 MW, including projects at Lake Hodges, Castaic Lake, Helms, San Luis Reservoir, O'Neill Forebay, Big Creek, and Oroville (Doughty et al. 2016). The 1,300 MW Eagle Mountain pumped storage project is in development and expected to be online in 2023. Pumped storage projects take a very long time to develop (~10 years) (Doughty et al. 2016).

Santa Clara Valley Water District recently considered a new pumped hydropower system between two existing reservoirs in their system. They planned to use excess energy from solar farms owned by the district to pump water between reservoirs, to be released later to produce energy. A feasibility study was conducted, and a cost estimate developed. The payback was more than 50 years. The cost did not include building new reservoirs, as the two reservoirs already existed. Rather, the cost was simply for installing switch gear, a substation, and a pump station. The difference between *retail* electricity rates when the system would be pumping versus producing energy was not enough to justify the expense of the system. Santa Clara Valley currently does have the capacity (or know how) to participate in the wholesale market and benefit from times when wholesale prices are negative during peak solar production. If Santa Clara Valley had a means to access wholesale negative prices and get contracts, that would change the economics of this pumped hydropower project (Brosnan 2019).

2.4.1.1 Practical Considerations

Valuing and compensating for flexibility – In the case of the Santa Clara Valley Water District pumped hydropower project, the costs of installing pumps, controls, and a new substation could not be recovered through operating the pumped hydropower facility. The economics may have been different if the energy prices during pumping were very low or negative during system solar peaks and the compensation for energy produced during non-solar hours (aka at night) were more reflective of the value. In addition, the value of ancillary services that could be provided by the pumped hydropower system was not monetized and included in the feasibility study. If large water systems are to support the grid through providing flexible supply, demand, and ancillary services, there must be a signal, a contracting mechanism, and appropriate compensation for those services.

The existing Helms pumped storage facility in California performs a night-day arbitrage, which is the traditional operation of pumped storage. But in CA today, the price signals for arbitrage are switched from normal day-night patterns. Now the plant pumps during the day and generates at night because the solar penetration has resulted in prices being weak during the day and relatively strong at night. Thus, the plant is still performing an arbitrage based operational pattern, but it is the opposite of the day-night pump-generate modes, even from a few years ago. Figure 3 illustrates the annual pumping energy at the Helms pumped storage facility together with the CAISO net load in the last week of March between 2012 and 2017.

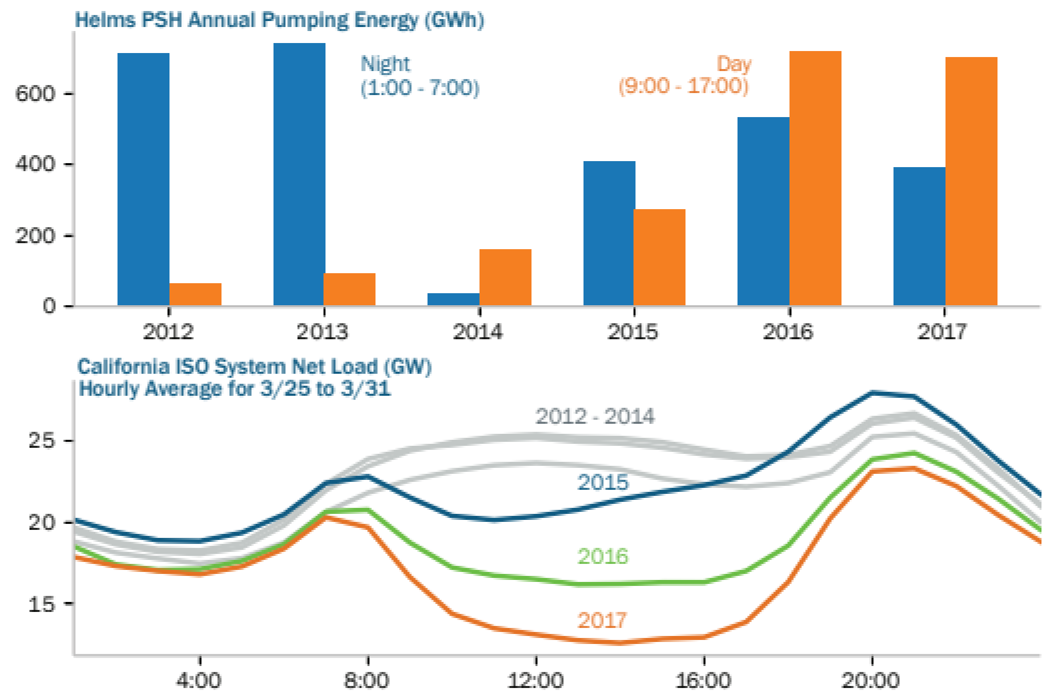

Figure 3. Annual pumping energy by Helms versus CAISO net load in the last week of March (2012-2017) (DOE 2017)

Los Angeles Water and Power's Castaic pumped storage project has similarly allowed the utility to negate the effect of a duck curve—the trough of net loads during the highest solar resource periods in midday followed by a severe afternoon ramp with the sudden loss of solar resource coincident with an uptick in electric loads. The suite of benefits from Helms, Castaic, and other pumped storage resources are not clearly available to a new pumped storage facility. This makes the cost-effectiveness uncertain over the lifetime of the plant (at least 40 years), and certainly at typically large scales where economies of scale can be achieved, especially if the entire cost of the project is born by compensation from electricity markets. San Diego County articulated the challenges and opportunities of pumped storage development—in particular, market and policy challenges—in a May 2019 whitepaper (SDCWA 2019). Of particular note for the study is its focus on the duration of storage. Typical battery storage systems can respond instantaneously to a signal but are energy-limited at four hours. Pumped storage systems are limited only by water availability for generation, and can be designed for much longer response timeframes, which opens up additional values and services that are not as well recognized (SDCWA 2019).

Integration with water supply resources – As shown by the relationship between existing water managers and pumped storage facilities in California, including the most recent construction of a pumped storage facility in the United States (SDCWA's Lake Hodges[1]), the economics for pumped storage may improve with existing facilities and motivation by water management for enhanced water supply. New water supply projects could be co-designed with power and water supply in mind, increasing the benefits and splitting up project economics into more favorable pathways.

[1] https://www.sdcwa.org/annualreport/2013/lake-hodges-pumped-storage-project

Scale – For smaller scale pumped storage resources, the cost of customized equipment and licensing can be extensive. Rather than building an individual and traditional design for a discrete pumped storage facility, it is possible to expand the control of storage, pumping, and generating to a system-wide function that performs in a similar manner and provides the same benefits, dispersed over an operational footprint. This would require optimization software and demonstration, as well as opportunities for aggregation of these functions.

2.4.1.2 Next Steps to Characterizing Potential

- Analyze the potential for co-design of water supply and pumped storage resources, as well as specific technical and economic considerations.
- Consider the technical potential for existing systems to function in a format materially similar to energy storage resources, the ability to take advantage of generating as well as pumping loads in a co-optimized manner. Consider regulatory barriers to market participation, design and technology options to utilizing pumps and generators within a system for this effect.
- Conduct in-depth literature review and interviews with water managers who operate pumped storage facilities—in particular, LADWP and San Diego County Water Authority—to understand the potential for co-optimized assets and integration with electric utility demand and market opportunities.

2.4.2 In-conduit Hydropower

In-conduit hydropower is used to generate electricity from reducing pressure in water pipes. In-conduit hydropower is best located where constant and consistent pressure reduction is required and where new additional infrastructure requirements are minimal (Sari 2019). Stantech is currently conducting a study for the Water Research Foundation and California Energy Commission (CEC) to identify in-conduit hydropower potential in California.[1] Past studies indicate untapped hydropower potential for California between 368 (from United States Geological Survey) and 414 MW (from Department of Water Resources (DWR) and State Water Resources Control Board (SWRCB)) exist for in-conduit hydropower in California (Badruzzaman et al. 2019). As Figure 4 shows, the current installed capacity of in-conduit hydropower in California is 343 MW. Most existing in-conduit hydropower systems are in Southern California. Figure 5 shows the installed and future capacities of in-conduit hydropower in California as estimated by DWR. As Figure 5 shows, there is significant untapped potential in the Bay Area. The Stantech project should be completed by the end of 2019.

[1] Stantec, NLine Energy, NSF ERC ReNUWIT and the Water Research Foundation are conducting collaborative research for a California Energy Commission project titled "California's In-Conduit Hydropower Implementation Guidebook: A Compendium of Resources, Best Practices, and Tools."

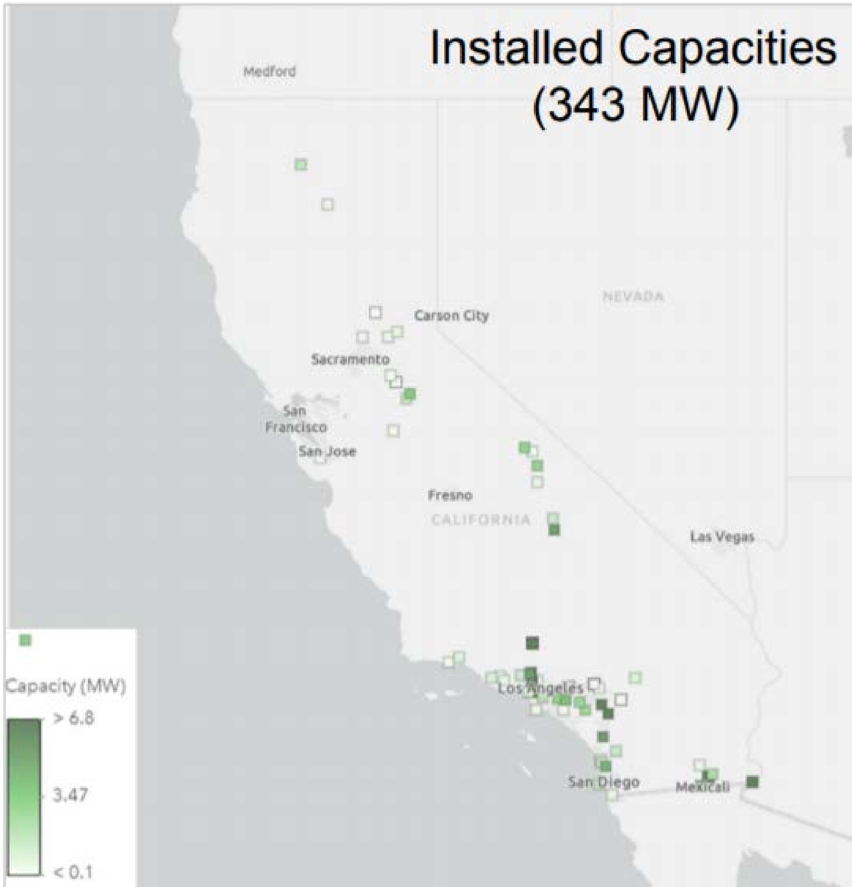

Figure 4. Current Installed Capacity of In-Conduit Hydropower in California (Badruzzaman et al. 2019)

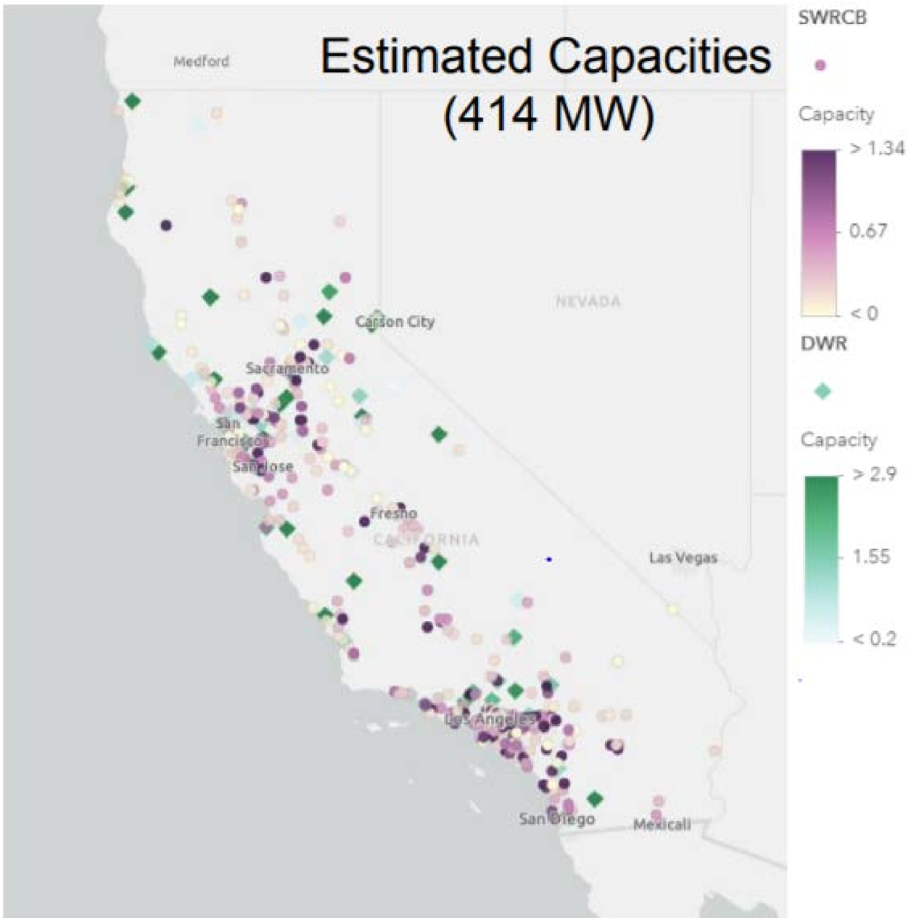

Figure 5. Projections of Maximum Uninstalled Capacity of In-Conduit Hydropower in California as per DWR and SWRCB (Badruzzaman et al. 2019)

2.4.2.1 Practical Considerations

Permitting – Recent Federal Energy Regulatory Commission reforms make installing in-conduit hydropower much easier due to a reduced level of review that is required. Federal approvals can be achieved in 45 days.

Conducive site conditions – Site conditions that support in-conduit hydropower generation include the following (Johnson 2019):

- Significant pressure reduction required (large elevation difference).
- Enough space existing around the existing pressure relieve valve to be retrofit with a generator. Turbine must fit on top of value and there needs to be elbow room in the vault. To reduce installation costs, can align upgrades with maintenance schedules.
- Load nearby that can be offset by in-conduit power generation so water utility can enter into a net metering arrangement.
- Community amenable to the project. Community issues and concerns (around sound and aesthetics) need to be addressed early on or else these can kill a project after significant work has gone into it.

2.4.2.2 Next Steps to Characterizing Potential

- Review final CEC report by Stantech on California's In-Conduit Hydropower Implementation Guidebook: A Compendium of Resources, Best Practices, and Tools (Badruzzaman 2019)
- Facilitate conversation between water utilities, electric utilities, regulators, and equipment manufacturers
- Characterize potential by region in terms of total energy, flexible capacity, and peak reduction
- Project costs of implementation
- Compare costs to benefits, including capacity and flexibility benefits.

2.4.3 Seasonal Pumped Storage

Seasonal water storage over large geographic distances is emerging as a novel concept in California to reduce energy costs and greenhouse gas emissions. Seasonal pumped storage by taking advantage of low energy prices and abundant renewable energy in the spring.

A recent study, completed by the consulting firm HDR for the California Energy Commission, analyzed a proposed Willow Springs Water Bank project with a potential economic benefit between $13 and $38 million per year to the State Water Project depending on actual wholesale market prices. The project entails a proposed 1,838 acre/500,000 acre-feet capacity aquifer water bank in Southern California near Los Angeles. Water would be pumped from Northern California to Southern California in the spring when renewable energy production (from wind and hydropower) are high and demand and prices are relatively low due to the lack of need for air conditioning. Water would be banked underground through groundwater recharge and then pumped out again and used to serve load in the Los Angeles area when electricity prices and demand are higher. The value of the energy-water bank is anticipated to increase as the amount of renewable energy on California's grid increases (HDR et al. 2019).

The Willow Springs Water Bank project would result in a net annual increase in total energy use because water must be pumped out of the groundwater facility in addition to regular State Water Project pumping. However, total energy costs and greenhouse gas emissions are lower because the most significant pumping is by shifted to lower-demand and lower-cost periods when renewable energy is available. The Willow Springs Water Bank plans to construct 40 MW of solar and a 5 MW hydroelectric turbine to generate power during groundwater recharge. The renewables on site will generate enough energy to make the whole operation energy-negative (HDR et al. 2019).

2.4.3.1 Practical Considerations

<u>Coordination</u> - Implementation of the water-energy bank concept will require participation of multiple local and state entities including Investor Owned Utilities (IOUs) and CAISO as well as other water resources management agencies and contractors.

<u>Incentives</u> - The primary benefits of the water-energy bank accrue to the grid and the project will require development of appropriate incentives to encourage stakeholder participation and for deployment.

<u>Implementation challenges</u> - Implementation challenges exist associated with supply contract terms, deliveries of water, carryover storage requirements and potential future changes to operation and storage policies.

2.5 Loss Reduction and Water/Energy Efficiency

Reducing the physical losses resulting from leaks in water infrastructure can also generate significant energy savings while reducing non-revenue water (i.e., water that utilities cannot financially recover) (Berger et al. 2016). During the roughly year-long mandate to reduce water consumption by 25% in California that came out in April 2015, approximately 1,830 GWh of energy was saved during that period (Spang 2018). The amount of energy saved through water conservation during that time was 11% greater than the amount saved through electric IOU energy efficiency programs during that same period, signifying the potential energy savings associated with reducing water consumption (Spang 2018).

Berger et al. showed that through the implementation of advanced metering infrastructure (AMI) for municipal utility-side leak detection, California has the potential to save 230 BG of water per year, which would lead to an embedded energy savings of 2.6 TWh/year. AMI is a development of advanced meter reading (AMR) technologies that builds upon AMR capabilities of more frequent data collection without the need of a manual meter reading by enabling two-way communication and advanced systems controls (Berger et al. 2016). The features of AMI also provide utilities with real-time analytics, like leak detection, and the ability to remotely shutoff a meter in the case of an emergency (Berger et al. 2016).

AMI offers the opportunity for utilities to detect small leaks in the systems to avoid larger, more costly issues with infrastructure and long-term losses. Two cities that implemented AMI, Leesburg, Virginia and Monaca, Pennsylvania, were able to reduce their non-revenue water from 15% to 7% and 50% to 15%, respectively (Ritchie 2015). Although technologies are readily available to enable leak detection, Berger et al. (2016) suggest there is a need to further explore the costs and benefits of AMI.

In addition to offering leak detection, AMI can also enable more energy efficient infrastructure design and operations. Current practices for designing pipes rely upon engineering best estimates of peak flow. With granular water consumption data collected with AMI, utilities can employ a data driven approach to more appropriately size pipes. AMI data can also aid in prioritizing pipe replacement in comparison to best-guess lifetime schedules, and help improve distribution redesign by more optimally sizing pumps in locations that had previously been over or under designed (Berger et al. 2016).

Making the case for AMI can be difficult, though, given the high capital costs of the equipment and the uncertainty of how the reduction in energy savings will be realized. Initially targeting locations where the embedded energy is highest, however, will enable the largest savings. Table 3 shows the energy intensity for different hydrologic regions in California (CPUC 2015)

Table 3. Total Energy Intensity by Hydrologic Region (KWh/AF) (CPUC 2015)

Region	Total Energy Intensity (kWh/AF)*
North Coast	2,170
San Francisco Bay	2,864
Central Coast	2,337

South Coast	3,727
Sacramento River	1,754
San Joaquin River	1,753
Tulare Lake	1,835
North Lahontan	1,754
South Lahontan	2,683
Colorado River	1,856

* includes energy used by investor and non-investor-owned utilities through customer end use

2.5.1 Practical Considerations

Prioritization – Prioritizing areas with high embedded energy would result in the largest energy saving per dollar spent.

Energy savings and costs may accrue to different parties – Energy benefits of water conservation can be significant, but they can also be dispersed, with a large amount of the savings from downstream measures realized by upstream energy supply savings. A life-cycle accounting methodology of energy savings realized by water saving measures, through AMI-based loss reduction or otherwise, would support policies where benefits and costs are accounted for and appropriately shared.

2.5.1.1 Next Steps to Characterizing Potential

- Conduct a literature review
- Perform a cost-benefit analysis of AMI-based leak detection in different energy intensity zones in California
- Characterize electric peak load savings resulting from different water efficiency measures
- Explore options for simple life-cycle accounting methodologies and templates as well as life-cycle based incentive options that address the disconnect between where costs and benefits accrue.

3.0 Synergistic Water and Energy Resilience

This section focuses on efforts being explored or undertaken that support water system resilience that could be synergistically applied to also support the electric grid.

3.1 Risk Assessment and Emergency Response Plans

The U.S. Environmental Protection Agency regulates water utilities in America based on its mandate to enforce the clean water and safe drinking water laws. On October 23, 2018, America's Water Infrastructure Act (AWIA) was signed into law. AWIA requires all community water systems serving more than 3,300 people to develop or update risk assessments and emergency response plans (ERPs). The law specifies components that the risk assessments and ERPs must address and establishes deadlines. An all hazards approach must be used. Water utilities must include natural disasters and malevolent acts. Standards that apply include G440 and G430 standards and RAMW-J100.

Climate change poses risks to water infrastructure. Climate change risks to water utilities that were discussed at the 2019 American Water Works Association Conference and Exhibition include the following:

- Many treatment plants (particularly WWTPs) in low coastal areas are at risk of inundation from sea level rise
- Inundation of pump stations and electrical gear
- Saltwater intrusion into drinking water supplies as sea levels rise and groundwater resources are depleted
- Greater spikes in wastewater volumes from storm events
- Increased sediment load from storms and fires
- Fires
- Power outages, including proactive power outages, to address wildfires.

If these threats can be addressed in a way that support energy management, this could be a win-win situation for water and energy systems. This could take the form of increased onsite generation, increased hydraulic storage, and/or ensuring that new or replaced equipment is demand response enabled. A conversation between water and electric utilities on opportunities here could be fruitful.

3.2 Self-Generation at Water and Wastewater Utilities

Proactive de-energization of power lines for wildfire prevention is a big concern for water utilities and is generating more interest in onsite generation (Haines 2019). By installing self-generation (biogas, gas, solar, wind, or geothermal) or battery storage, water and wastewater utilities can reduce costs, improve system resilience and reliability, and reduce greenhouse gas emissions (Kenway et al. 2019).

Each organization is unique. Cost effectiveness of implementing DERs at water and wastewater facilities depends on site-specific factors, such as system layout, space, flowrates, air permitting requirements, and existing enabling technologies and capabilities. Tariffs, applicable policies, and regulations also factor into cost effectiveness.

Kenway et al. (2010) looked at technical and economic feasibility of implementing distributed generation, storage, or demand response at water and wastewater facilities. They conducted a survey of water and wastewater utilities. The key factors that were identified for the success of incorporating DERs into water and wastewater utilities include economic and technical feasibility, clear and realistic expectations, leadership to overcome institutional barriers, and cooperation between stakeholders and sectors (Kenway et al. 2019). The specific policies and activities that most positively supported distribution generation were: net metering incentives, energy performance contracting, and third-party contracting with power purchase agreements. Constructing or instituting DER is capital-intensive, and in some cases can have an uncertain revenue stream. Policies that support cost recovery surety and economic feasibility of projects can address financial barriers.

3.3 Desalination

Several municipalities have shown notable resilience benefits of desalination for potable water supply amidst climate change pressures. The city of San Diego has turned to large scale coastal desalination in the wake of decreased Rocky Mountain snowfall, the subsequent Colorado River flows, and recurring multi-year droughts (Robbins 2019). The city of Santa Barbara, which depends on the State Water Project and groundwater in equal parts for approximately 80% of its water supply, has responded to decreased snowpack in the Sierra Nevada mountains as well as drought conditions by recommissioning an emergency desalination plant (Santa Barbara County 2019). Both cities have achieved a more resilient supply with the help of desalination. The state has 11 existing seawater desalination plants that produce a total of 65.5 millions of gallons per day (MGD). Most of this capacity (60 MGD) is concentrated at the Carlsbad Seawater Desalination Facility in San Diego. Desalination of brackish groundwater is also well established, with 27 currently existing facilities producing 131 MGD across the state.

Projecting further aridification of the west, future projections show growth of desalination in the resource mix. Four additional seawater desalination facilities with a combined capacity of 105 MGD are under consideration for permits. Large plants in Redondo Beach (20 MGD) and Dana Point (15 MGD) are in environmental review, and a facility in Huntington Beach (60 MGD) has been active in the permitting process since 2002. Brackish groundwater desalination projects tend to be smaller and more distributed in location. An additional 10 brackish groundwater desalination projects with a combined capacity of 32 MGD are in planning or permitting stages, and one brackish groundwater desalination site is currently under construction in Monterey county with a capacity of 3.1 MGD. California Regional Water Quality Control Boards in regions 3, 4, 5, 8, and 9 are actively reviewing brackish water desalination proposals.

However, desalination remains a small contributor to California water supply. California uses 55–93 BGD for applied water use on average; the total of all projects proposed, under construction, or in operation is 361 MGD (PPIC 2019). Significant cost and environmental hurdles stand in the way of more widespread adoption. One acre-foot of water sourced from the Colorado River and conveyed to San Diego costs approximately $1200. The equivalent volume of water sourced from the Carlsbad desalination plant costs $2200 (Robbins 2019). However, cost is falling due to global applications. Israel’s Sorek plant (165 MGD) has enlisted pressure tube design, pump efficiency, and energy recovery to yield rates of $715 per acre-foot (Talbot 2015).

Seawater desalination requires 2.5–4.0 kWh of energy per cubic meter of water output. Brackish water desalination, by contrast, requires 2–4 times less energy, or roughly 1.0–1.5 kWh per cubic meter (Talbot 2015). With the right level of cooperation between water and energy providers, some cost relief may be seen through demand response programs. EMWD is currently curtailing a 4 MW reverse osmosis processing load when requested and has volunteered their desalination operations in demand response programs through local aggregators for more than 10 years (Robinson 2019).

Environmentally, sub-surface intake at depths of 10–100 feet below the sea floor and collocated discharge where brine mixes with wastewater for downstream processing are the preferred technologies of state regulators. Plants with these designs can more quickly navigate the permitting gauntlet of the California Coastal Commission and the California Regional Water Boards, the latter of which retains final authority. No project has made it through the process since Carlsbad in 2015 (Luster 2019).

4.0 Incentives, Support, and Change Management

Water utility employees are conscientiously focused on their mandate of providing safe and reliable water at reasonable costs. They are also focused on fulfilling their current permit requirements. Without incentives and support, it is unlikely they are going to change behavior and/or make additional investments to manage energy.

This section includes ideas and recommendations based on the 20+ individuals that were interviewed or consulted in the development of this report.

- Change and risk management – The water industry in California is very heterogeneous, with more than 7,000 utilities providing service, the majority of which are governed by local boards. Some are very large and sophisticated, while others are small with a limited understanding of energy options and opportunities. One thing many water utilities have in common is their resistance to change. With change comes increased trial and error, potential operator headaches, potential water quality or water supply issues, and even potential permit violations. Change management is something that would be helpful in this situation, along with upper level support. Some folks we spoke with in the development of this report say that water utilities will only change their behavior if they are forced to. Water utilities are risk averse. Some utilities expressed concern that if they voluntarily start participating in things like climate mitigation programs, then they are going to get overwhelmed by regulatory practices and get roped into things they do not understand, such as cap and trade.
- Revenue pressure at water utilities – Many water utilities are facing decreasing sales at the same time much of the water infrastructure in the United States is reaching the end of its useful life. Sales are down, due in part to efficiency measures that have been implemented over the last 30 years and because a decline in the number of individuals per residential household (Qureshi and Sha 2014). Additionally, weather and fire risks are increasing in some areas. All of these combine to put upward pressure on water rates. Reducing water utilities' energy costs and providing new revenue opportunities, through synergistic coordination with electric utilities, is one way to counter the upward pressure on water rates.
- Access to capital – It can be difficult for water and wastewater utilities to spend money on investments that are not within the scope of traditional water service provision of regulatory compliance obligations. In addition, many utilities struggle to secure upfront capital needed. This is a barrier to investments that support energy management (Christian-Smith and Wisland 2015).
- Expanding the focus to include energy costs – For many utilities, energy costs are simply treated as a pass-through to customers. In communicating with their regulators, water utilities must show a reasonable amount of due diligence, but there are not specific metrics or incentives for reducing energy costs. Therefore, there are no compelling incentives that would support a utility making changes and taking risks to manage electricity costs. WWTP operators are graded based on keeping the dissolved oxygen levels within a given setpoint. If they use more energy to do this, they are not penalized. If energy is to become a focus of water utilities, high-level guidance and performance incentives need to be provided.
- Strained relationships with electric utilities – It was reported that, in many instances, water utilities do not trust their electric utilities (particularly very large electric utilities). As such, water utilities do not want to give information to the electric utilities, and water utilities do not feel there is someone they can go to for unbiased information about energy management or engaging in electric utility programs. Assistance outside of the IOUs would be helpful. Third-

party liaisons can be a good way to go for some utilities, including the fact they can help spread and absorb some of the risk associated with demand response programs. Some water utilities report that their electric utilities will not give them "the time of day" because their loads and accounts are distributed, and they are not considered "large customers" with designated large customer account managers. Opportunities for increased coordination, understanding, and trust-building are critical.

- Contractual relationship with electric utility – Some water utilities have agreements with electric utilities that keep them from becoming a net producer of energy. This was true with the City of Oceanside San Luis Rey facility, which has an existing 600-kW cogeneration plant. San Luis Rey staff were working with Lawrence Berkeley National Lab on a potential demand response measure, but San Diego Gas & Electric has a contract with the City of Oceanside that requires them to be a net consumer of energy at all times. This requirement restricted the amount of load reduction the facility can provide for demand response (Sparn and Hunsberger 2015).
- Clear and sufficient financial incentives – Opportunities exist. However, at the end of the day, there must be a financial benefit to water utilities. Incentives need to be large enough. Financial incentives need to be structured to help utilities install the equipment they need to participate. Some utilities suggested that, because they are not experts in energy, incentives need to be simple enough to understand that they can be worked out through back-of-the-envelope type calculations. In terms of time-of-use rates, utilities do not want to have to work too hard to adjust operations to respond. Some expressed a desire for a straight-forward rate or two-tier rate. It should not be too complicated.
- Regulation – Some individuals we spoke with in the development of this report indicated that the water industry does not change very fast unless it is forced to by regulation. They thought financial incentives alone are not enough, and the main driver for change is regulation. Without regulations, water utilities will do it the way they have always done it. The U.S. Environmental Protection Agency (EPA) is the primary regulator for the water industry in the United States. They regulate hydraulics (pressure) and water quality. Energy efficiency benchmarks could be developed, and energy regulations could be based on those (with exceptions for extraordinary circumstances). Regulations could also be formulated around the development of energy management plans or requirements for demand response capable equipment at the time of equipment replacement. Kenway et al. (2019) found that the regulatory environment poses a significant barrier to DER implementation, and there is a need for support for policies addressing DERs and renewable energy. Integrated planning across water and electricity sectors is still rare, potentially in part due to lack of a common language. Integrated planning could lead to efficiencies and opportunities. Water could be more explicitly addressed in electric utility Integrated Resource Planning (Kenway et al. 2019).
- Management support – The tone is set at the top of an organization. For a utility to include energy management as a mission focus, the mandate for energy management (increasing mission beyond water management only) needs to come from very high up in the organization.
- Information – There is a lack of publicly available information about electricity consumption and generation by water and wastewater utilities. Past studies have recommended that the state collect better data about water-related electricity use and generation (CPUC 2010a; CPUC 2010b; CEC 2006).
- Education and support – Education for water utilities is still an important barrier. There is a big difference between large and small water agencies in terms of technical capacity and

labor force. For example, not all utilities have the capacity to really consider operational changes that should be made in response to time-of-use rates. This is true of energy generation technologies and options as well. Association of California Water Agencies has preferred provider programs for solar systems and battery equipment, and they offer things like standard requests for qualifications (Haines 2019). Additional training is needed for water utilities to incorporate renewable energy into their operations. It can be difficult for utilities to learn about the cost savings and financial incentives associated with demand response programs. Generally, water agencies do not feel like they have as much expertise in the energy field. They feel inexperienced and not empowered to influence policy.

- <u>Incentives/disincentives for electric utilities</u> – Traditional electric utilities may be less than enthusiastic about and feel challenged by new distributed customer-owned generation and storage. This can manifest as barriers to cooperation. This is particularly true where revenue streams of electric utilities are impacted (Kenway et al. 2019). This is a fact that should be considered when thinking about incentives and change management.

5.0 Summary and Recommendations

There are a range of options available for water and wastewater utilities in California to pursue the installation and adoption of DERs. This report outlines five key opportunity areas, including responsive demand, pump system efficiency improvements, biogas, hydropower, and loss reduction and water/energy efficiency. Each of these opportunity areas exists alongside potential barriers and enabling support mechanisms that will influence the extent to which they are developed across the state. Every utility is unique in its size, capabilities, and staff, making some DERs more suitable for particular utilities over others. Empowering utilities to engage with the idea of changing their energy management practices will likely require educational outreach, management support, and collaboration among a range of stakeholders.

Ultimately, DER implementation at water and wastewater facilities should not be considered in a silo. Many initiatives and efforts related to climate change and extreme weather events in California may open opportunities for streamlined adoption or DER prioritization from utilities. From emergency response plan requirements for water utilities to onsite generation needs during times of de-energization, DERs may see opportunities to serve more than one purpose.

To understand the full potential of DERs at water and wastewater facilities, determining the technical and economic potential would be a reasonable next step. A series of conversations between electric and water utilities, potentially convened by DOE and CPUC, could support developing and shared understanding of practical opportunities in the near and longer term.

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